Sealing mechanisms at pore scale, and consequences for hydrocarbon exploration

Dissertation for the degree of Doctor Philosophiae

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CONCLUSIONS / IMPLICATIONS

This dissertation was motivated by the realization that four concepts, which are too simplistic, are widely assumed in the petroleum industry:

First, mechanical compaction and associated disequilibrium compaction are frequently assumed to be the main mechanism for overpressure formation, although data are rarely given to support this assumption. This thesis concludes that neither the North Sea nor the Haltenbanken shales compacted mechanically at moderate to deep burial. Therefore, high overpressures in these rocks were not caused by disequilibrium compaction, but more likely by diagenetic processes that were largely unaffected by fluid pressures. Traditional seismic and log-based pore pressure detection methods in these areas should be expected to result in under-prediction of fluid overpressures because the porosities are not higher in overpressured shales than in normally pressured shales.

Second, observations of zods (zones of deteriorated seismic signals; at times termed gas chimneys) are often interpreted as evidence of hydrocarbon leakage. This thesis concludes that the occurrence of zods may identify hydrocarbon leakages and where pressure compartments leak. However, prior to interpreting these zones as hydrocarbon leakage, the interpreter must be aware of the various geological processes and non-geological origins that could cause such velocity variations: (a) hydrocarbon leakage, (b) leakage of water with dissolved gas (that could create an inhomogeneous gas saturation), (c) fault or fracture zones themselves, (d) fluid leakage above fault(s) or fault junction, or (e) data quality issues. As a result, applications of zods in hydrocarbon prospect evaluation should be performed more carefully than what is often seen in the industry today.

Third, the consequences of high overpressures are often assumed to be hydrocarbon leakage through the caprock – either because of hydro-fracturing or because high water pressure force oil or gas through membrane seals. This thesis concludes that high overpressures are compatible with hydrocarbon preservation. Vertical water leakage from the apex of a trap may take place while oil and gas are retained by capillary forces within the structure. This result is consistent with the fact that several of the largest oil fields on

the Norwegian Continental Shelf (Statfjord, Gullfaks, Snorre, Visund, and Kvitebjørn) are highly overpressured and leaky, and yet contain vast amounts of oil and gas.

Finally, vertical leakage is often assumed to occur as separate phase oil flow through water-wet caprock shales, and membrane seals will, according to the definition of capillary entry pressure, preserve oil indefinitely as long as the critical pore throats are sufficiently small. This thesis concludes that residual water, which flows through reservoirs and caprocks, carries polar compounds that locally change the caprock wettability, thus resulting in the formation of oil-wet flow paths. This suggestion explains how pore-scale migration can take place through caprock shales without resulting in extensive oil saturation in these shales. The suggestion further implies that membrane seals deteriorate with time, thus promoting the transient nature of oil pools that are observed, but that are not compatible with endless membrane sealing time.

PREFACE

This dissertation entitled "Sealing mechanisms at pore scale, and consequences for hydrocarbon exploration" consists of seven (7) main papers where I am the first author, four (4) co-authored papers where I have contributed significantly, and four (4) other co-authored papers where my contributions have been less significant and largely have consisted of feedback and participation in discussions. The papers address the topics of shale compaction and overpressure, seismic characteristics of fluid leakage and membrane caprock sealing.

The research has been carried out at the Research Centre at Statoil / StatoilHydro at Rotvoll, Trondheim, Norway, as a part of regular project work in various research projects. Both the laboratories at StatoilHydro (Rotvoll, Trondheim) and Reslab (Stavanger and Trondheim) as well as consultants (NumericalRocks) have made important contributions to the research.

My research work has also benefited from research by Hege M. Nordgård Bolås (StatoilHydro, Research Centre Trondheim). Her work has also culminated in a dissertation this year, entitled "Sealing mechanisms and hydrocarbon trap integrity in overpressured sedimentary basins" (University of Bergen, Norway). The teamwork with Hege has been very good, and has resulted in numerous exchanges of ideas in topics that are in the borderland between her research and my own.

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I am very grateful to Statoil / StatoilHydro for granting permission to publish my scientific work. I also give my gratitude to the referees and the discussion partners of all my technical papers as acknowledged in each of the papers. I also appreciate the graphical support by the technical staff at the Research Centre Trondheim, StatoilHydro, and the editorial language assistance by S. Clarke (NTNU) with parts of this thesis.

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Gunn Mari Grimsmo Teige

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LIST OF THE MAIN PAPERS INCLUDED IN THIS THESIS

1. TEIGE, G. M. G., HERMANRUD, C., WENSAAS, L., AND NORDGÅRD BOLÅS, H. M. (1999) The lack of relationship between overpressure and porosity in North Sea and Haltenbanken shales. Marine and Petroleum Geoscience, vol. 16, no. 4, p. 321-335.

2. TEIGE, G. M. G., HERMANRUD, C. KLØVJAN, O. S., ELIASSEN, P. E., LØSETH, H., AND GADING, M. (2002) Evaluation of caprock integrity in the western (high-pressured) Haltenbanken area – a case history based on analyses of seismic signatures in overburden rocks, In: A. G. Koestler and X. Hunsdale (Eds.) Hydrocarbon Seal Quantification. NPF Special Publication 11, p. 233-242.

3. TEIGE, G. M. G. AND HERMANRUD, C. (2004) Seismic characteristics of fluid leakage from an underfilled and overpressured Jurassic fault trap in the Norwegian North Sea. Petroleum Geoscience, vol. 10, p. 35-42.

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6. TEIGE, G. M. G., HERMANRUD, C., WENSAAS, L., AND NORDGÅRD BOLÅS, H. M. (2007) Geological constraints of pore pressure detection in shales from seismic data. Basin Research, vol. 19, p. 33-50.

7. TEIGE, G. M. G., HERMANRUD, C., AND RUESLÅTTEN, H. (*Submitted to Geology*) Membrane seal leakage through establishment of oil-wet flow paths.

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8. Hermanrud, C., Wensaas, L., Teige, G. M. G., Vik, E., Nordgård Bolås, H. M., and Hansen, S. (1998) Shale porosities from well logs on Haltenbanken (Offshore Mid-Norway) show no influence of overpressuring, In: Law, B.E., G.F. Ulmishek and V.I, Slavin (Eds.) Abnormal pressure in hydrocarbon environments. AAPG Memoir 70, p. 65-85.

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12. Nordgård Bolås, H. M., Hermanrud, C., and Teige, G. M. G. (2004) Origin of overpressures in shales; constraints from basin modeling. AAPG Bulletin, vol. 88, no. 2, p. 193–211.

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1. INTRODUCTION

The research in this dissertation addresses three different, but related topics. These topics are: (1) sediment compaction and overpressure (covered by main papers 1 and 6, and the co-authored paper 8), (2) seismic characteristics of fluid leakage (covered by main papers 2 and 3), and (3) caprock membrane seals (covered by main papers 4, 5 and 7, and the co-authored paper 10). The remaining papers address the practical consequences of the research that has been carried out (covered by co-authored papers 9 and 11). This chapter gives a scientific background to the main research topics and points to some major challenges within these topics.

1.1 Scientific background and challenges

1.1.1 Sediment compaction and overpressure

Sediment compaction is influenced by both mechanical and chemical processes. As uncemented rocks are compressed vertically during burial, their porosity change depends on the change in effective stress (σ'), defined as $\sigma' \cong \sigma - P$, where σ is the total stress transmitted through the solid matrix, and P is the pore fluid pressure. It is commonly assumed that porosity loss is likely to be dominated by effective stress related mechanical compaction during early burial, while thermally controlled mineral reactions dominate the porosity reduction at higher temperatures. Muller (1967), in his discussion of diagenesis in argillaceous sediments, suggested that mechanical compaction stops at burial depths around 500 m. The validity of fluid pressure versus effective stress relationships is also discussed by others, e.g. Bradley (1975), inherently assumed that thermally driven diagenetic reactions are also responsible for porosity loss in shales at high temperatures (Bradley, 1975; Bjørlykke, 1998). Geochemical models for sedimentary diagenesis suggest that precipitation of diagenetic clay minerals at temperatures >60°C result in severe permeability reductions in shales/mudstones, rendering the affected sedimentary sections prone to overpressure development (Nadeau et al., 2002).

If pore fluids are free to escape from the pore network of the sediments as they compact mechanically, then the porosity will become a function of the effective stress. If, however, the pore fluid escape is restricted, an increase in pore fluid pressure will result, thus reducing the mechanical compaction. This process is often referred to as disequilibrium compaction or undercompaction. The principle of undercompaction states that overpressured rocks have higher porosities than normally pressured rocks at a similar burial depth (Dickey, 1974). Disequilibrium compaction is the most frequently advocated overpressure mechanism – also in the North Sea (Swarbrick and Osborne, 1998), which is one of the main study areas of this thesis.

In one of the first studies of abnormal pressures, Dickinson (1953) defined overpressure as "any pressure which exceeds the hydrostatic pressure of a column of water or formation brine". Based on data from the Gulf of Mexico, he suggested that the high pressures in the clastic sequence there could be explained by incomplete dewatering of sediments. Other explanations were later suggested for the high pressures in these rocks, including thermal effects (Barker, 1972), clay mineral changes (Powers, 1967; Burst, 1969; Bruce, 1984) and osmosis (Marine and Fritz, 1981). In other basins, overpressured reservoirs have been explained by the influence of hydrocarbon generation / maturation (Spencer, 1987), and gas generation (Hunt et al., 1994). One dominant mechanism for overpressure formation is often suggested, most frequently disequilibrium compaction (Bredehoeft and Hanshaw, 1968; Summa et al., 1993; Swarbrick and Osborne, 1998), or hydrocarbon generation (Meissner, 1978).

Pennebaker (1968) and Reynolds (1970) further claimed that overpressured rocks in the US Gulf Coast area were associated with abnormally low acoustic velocities. They suggested that these low velocities were the result of variations in geological age and lithology, and that elevated porosity was caused by restricted fluid escape during sediment compaction (undercompaction). They therefore suggested that analyses of acoustic velocities from seismic data could be applied to quantify pore fluid pressures, inherently suggesting that the method is only applicable in areas were the impact of age and lithology variations on acoustic velocities are of secondary importance. Pore pressure detection methods are sensitive to the mechanisms that generate the pore pressures and overpressures, and overpressures generated by fluid expansion mechanism may be

underestimated if they are founded on porosity-based pressure detection techniques (Bowers, 1995).

While disequilibrium compaction is the most frequently advocated overpressure mechanism, data which clearly support this mechanism are rarely given. As a result of the widespread belief in disequilibrium compaction mechanism, most pore pressure detection methods are based on the concept that overpressured shales have elevated porosities due to undercompaction. However, the application of such methods is not straightforward as changes in well log responses may result from changes in lithology as well as from changes induced by different fluid pressures, and may also vary with the mechanism of overpressure formation.

Increased awareness is needed concerning the conditions under which the pore pressure detection methods are used. Successful pore pressure detection therefore requires that the contribution of effective stress variations to acoustic velocities can be resolved from other factors that influence such velocities. Such factors include both rock properties (mineralogy, sorting, grain size, and cementation) and the accuracy of velocity determinations from well logs and seismic data.

1.1.2. Seismic characteristics of fluid leakage

As chemical compaction of sediments starts at shallow to moderate burial depths - regardless of the pore fluid pressure - the porosities decrease with depth and temperatures. Accordingly, fluids must escape from their pressure compartment as the porosities are being reduced. This is because the compressibility of water is low, and only insignificant porosity reductions can be accommodated by compression (and associated pore pressure increase) of the water. As a result, virtually all pressure compartments leak. This statement also applies to the main parts of the North Sea and Haltenbanken areas.

Several cases of emptied structures resulting from vertical leakage have been described, e.g. in the western, highly overpressured part of the Halten Terrace. However, complete reservoir drainage is not necessarily a consequence of vertical hydrocarbon leakage. The leakage can take place from a down-dip position, while hydrocarbons above this position

are kept in the reservoir. Furthermore, active leakage may take place from the apex of hydrocarbon-filled structures without emptying them. This is the case when the leakage rate is sufficiently low compared to the in-place volumes or the migration of hydrocarbons to the structure. Seal analyses in hydrocarbon exploration should therefore not focus on whether a pressure compartment leaks or not, but on where it leaks, which leakage process is active and which fluid type it is that leaks.

Seismic data reflect changes in rock and fluid properties in the subsurface. Leaking oil or gas may therefore result in lateral density and / or velocity changes that reveal the presence of fluid leakage. Such lateral variations may lead to vertical zones of deteriorated seismic signals (zods).

Fluid overpressuring (which is a main factor related to fluid leakage) may result from a variety of mechanisms (Swarbrick and Osborne, 1998), including disequilibrium compaction, thermal expansion of pore fluids, loss of bound water arising from the smetite-illite transformation at depth, hydrocarbon generation and maturation in kerogen rich source rocks, and tectonic stress. Accordingly, zones of deteriorated seismic signals differ with geological setting and stratigraphy, geographic area, leakage mechanisms (leakage through fractures or membranes), depth, and seismic data quality.

A large number of studies have used reflectivity contrasts in overburden rocks as an indication of hydrocarbon presence. Several investigations have documented the coexistence of reduced reflectivity or blurred seismic images and fluid migration pathways in sediments without having the influence of gas independently verified (Abrams, 1992; Traynor and Sladen, 1997; Heggland, 1998; Story et al., 2000; and Tingdahl et al., 2001). In particular, and although seismic expressions of fluid leakage may vary a lot, the existence of zods in overburden rocks is often interpreted as evidence of vertical leakage of hydrocarbons from underlying reservoirs (O'Brien et al., 1998; Symington et al., 1998; Løseth et al., 2002). Generally, the visual appearances of proposed avenues for hydrocarbon migration vary significantly, and such appearances are probably related to a variety of geological processes. The interpretation of these seismic images as being hydrocarbon-related is in most of the above-mentioned cases supported by other evidence. Even so, it is important to realize that vertical zones of seismic degradation can be caused

by factors that are unrelated to the presence of gas (although some of these are often associated with hydrocarbon presence).

Zods may be located above intact accumulations (e.g. Gullfaks), including hydrocarbon accumulations that leak slowly compared to the hydrocarbon supply rate. In the latter case, assessing how the leakage process takes place is of importance. Also, zods may reflect rapid leakage processes, but still be associated with commercial hydrocarbon deposits, provided that they reflect leakage significantly below the apex of the structure.

In addition, zods need not be evidence of hydrocarbon leakage; they may also result from water leakage, provided that gas comes out of solution as the water moves towards a lower pressure. Arntsen et al. (2006) have proposed a simple acoustic model explaining the main features of gas chimneys (zods that are interpreted to result from gas leakage), stating that inhomogeneous gas saturation results in an inhomogeneously fluctuating compressional velocity field that distorts seismic waves. Gas presence in sediments alone does not lead to deteriorated seismic signals.

The importance of identifying whether zods actually result from hydrocarbon leakage is crucial in hydrocarbon prospect evaluation. So is the ability to separate the seismic characteristics of fatal leakage from those of non-fatal leakage. Such separations require knowledge of the leakage processes, and also knowledge of the limitations and multiple interpretations of leakage-related seismic expressions. Learning to know the limitations of seismic methods for leakage identification is arguably the most critical factor in seismic identification of hydrocarbon leakage.

1.1.3. Caprock membrane seals

Caprock seals can be divided into those that fail by capillary leakage (membrane seals) and those whose capillary entry pressures are so high that seal failure occurs by fracturing and / or wedging open of faults (hydraulic seals) (Watts, 1987). Membrane seals, which are the main focus of this thesis, prevent hydrocarbon leakage when capillary forces exclude hydrocarbon intrusion through the pore throats of the water-wet seal (Watts, 1987).

Capillary pressure (P_c) at the boundary of the reservoir and the caprock is defined as the difference between oil pressure and water pressure:

$$P_c = P_o - P_w = (\rho_w - \rho_o)gh + 2\gamma cos\theta / r_{res}$$

Here, P_o is the oil pressure, P_w is the water pressure, ρ_w is the density of formation water, ρ_o is the density of oil, g is the acceleration of gravity, h is the height of the hydrocarbon column, γ is the hydrocarbon-water interfacial tension, θ is the wettability of the reservoir, expressed by the contact angle of oil and water against the solid, and r_{res} is the radius of pores in the reservoir rock. Berg (1975) defined the capillary entry pressure (P_{ce}) of a water-wet caprock as:

$$P_{ce} = 2\gamma cos\varphi / r_{seal}$$

Here, φ is the contact angle between oil and water in the caprock, and r_{seal} is the radii of pores in the caprock. When a breakthrough of hydrocarbons occurs, this angle is zero ($cos\varphi =1$). Accordingly, membrane seals do not allow hydrocarbon migration or leakage to take place unless the hydrocarbon buoyancy exceeds the capillary entry pressure ($P_c > P_{ce}$).

England et al. (1987) addressed situations where the aquifer overpressure in the reservoir exceeds the fluid pressure in the caprock, and suggested that the differences between these fluid pressures (ΔP) should be subtracted from the capillary entry pressure of the caprock in calculations of capillary sealing:

$$h = 1/\Delta\rho g \times (2\gamma / r_{seal} - \Delta P)$$

A different opinion was given by Bjørkum et al. (1998) who suggested that water-wet reservoirs beneath water-wet seals have a continuous water phase through the reservoir and into the seal, and that this water phase is mobile. Consequently, they suggested that hydrocarbons beneath the seal are not subjected to a significant upward force due to

overpressure in the water phase of the reservoir. As a result, overpressured water-wet reservoirs should not be considered more prone to capillary leakage than normally pressured reservoirs.

In a discussion paper Clayton (1999) disputed the water phase being continuous, whereas Rodgers (1999), in another discussion paper, pointed out that the so-called "irreducible" water saturations can have extremely low mobility, but as long as the water phase is interconnected at low saturations, the water permeability might be very small but never zero. Rodgers' (1999) observations were consistent with the results of Dullien et al. (1986) and Melrose (1990), whose laboratory experiments demonstrated that residual water is mobile and that there is apparently no lower limit of the residual water saturation (that is; in theory no "irreducible" water phase saturation exist.). In the forthcoming discussions this water is referred to as residual water.

Laboratory experiments that simulates water flow through water-wet and oil-saturated core plugs, and further through a water-wet membrane had not been published. Such experiments would resolve the disagreements and uncertainties stated above. Such experiments would also help to clarify the issues of (a) the continuity of the water phase, and (b) the permeability of this phase, especially if the experiments could be performed at capillary pressures similar to those existing at the top of economically significant hydrocarbon columns.

Larter et al. (2000) performed laboratory experiments to investigate the effects of petroleum fractionation and wettability changes that occurred during oil flow through a siltstone with no or non-perfect top seal. These experiments demonstrated that the water effectively removes hydrophobic components (carbazoles, benzocarbazoles and phenols) from migrating petroleum by partition-sorption processes, and result in wettability changes. Bennett et al. (2004) further reported limited changes in bulk petroleum compositions during the fractionation, suggesting that small amounts of polar components were involved in the wettability alterations. These results are significant in the context of this thesis because membrane sealing of oil can only operate below water-wet seals.

Leakage through shaly sequences is often envisioned as hydrocarbon percolation through water-wet pore networks. Alternatively, it has been perceived as two-phase flow in oil-wet

pathways, which have evolved as a consequence of diffusion of hydrophilic organic compounds into caprock or mudstone pores (Aplin and Larter, 2005). In both cases, and contrary to observations, such leakage would result in oil saturations of the coarser layers of leaky inhomogeneous caprocks, and also in shales that lay between the source rocks and the carrier beds (although exceptions occur; e.g. in extensive micro-fractured caprocks; Leith et al., 1993; Leith and Fallick, 1997). The lack of such saturation has thus been a weakness in our understanding of vertical oil migration. Also, capillary trapping would result in an almost endless hydrocarbon residence time in reservoirs overlain by thick caprock shales. The observation that the residence time of giant oil fields is restricted (average 35 Ma according to Macgregor, 1996), thus points to another weakness in our understanding of hydrocarbon sealing mechanisms.

1.2 The objectives of the thesis

The main objective of this thesis is to present research results that improve our knowledge of;

- (a) **leakage processes in the subsurface**, and
- (b) **how hydrocarbon leakage can be identified**.

The analyses started with early investigations of the operating compaction processes in shales of the Norwegian Continental Shelf (Paper 1). These studies were followed by investigations of the consistency between the basis for pore pressure prediction of North Sea shales and the geological processes that are responsible for shale compaction here (Paper 6).

Work related to seismic identification of hydrocarbon leakage in overpressured regions is presented in Papers 2 and 3. The purpose of these papers was to examine sources of uncertainty in seismic identification of hydrocarbon leakage, and to determine how indications of hydrocarbon leakage from seismic data should be accounted for in hydrocarbon exploration.

More in-depth analyses of leakage mechanisms are presented in Papers 4, 5 and 7. The most extensive work efforts included obtaining experimental evidence for, and quantification of, movement of residual water in hydrocarbon-filled reservoirs. This work allowed a quantification of the influence of overpressures on membrane sealing capacity. Finally, the work on membrane seals resulted in a refined model for hydrocarbon leakage in shales through oil-wet flow paths.

Specific objectives are:

Sediment compaction and overpressure

* To examine log data from shales in the Norwegian sector of the North Sea and in the Haltenbanken area to test whether disequilibrium compaction (undercompaction) has caused the fluid overpressures here. (Paper 1)

* To investigate the relationships between acoustic velocities (from well log data) and pore pressures in shales offshore Norway, and their dependence on geological variations. This was done to identify geological conditions that are favourable for seismic pore pressure predictions. (Paper 6)

Seismic characteristics of fluid leakage

* To compare the seismic characteristics of fluid leakage in overburden rocks in the western high-pressured Haltenbanken area with those of the eastern normally pressured area to see whether zods (zones of deteriorated seismic signals) appear more frequently in areas with high frequencies of fatal leakage than in areas with low leakage frequencies. The investigations were done on both 2D and 3D seismic data. (Paper 2)

* To investigate seismic signatures in an overburden post-rift sequence in order to identify leakage position(s) which controls the hydrocarbon column height in the structure drilled by Well 35/10-2. (Paper 3)

Caprock membrane seals

* To perform a laboratory experiment to investigate whether residual water migrates through a water-wet and oil saturated sandstone while the oil is retained by capillary forces (by a membrane), and also to determine the permeability of the residual water. (Paper 4)

* To perform multiple residual water flow experiments in order to establish a relationship between the relative permeability to residual water and other parameters in water-wet reservoirs. (Paper 5)

* To present a refined membrane seal leakage model that is consistent with the experimental results of Papers 4 and 5, and that explains the hitherto unexplained lack of oil saturation in coarser layers of leaky inhomogeneous caprocks (and also shales that lay between source rocks and carrier beds, although exceptions occur), and that also explains the transient nature of oil pools with adequate membrane seals. (Paper 7)

2. SUMMARY OF THE MAIN PAPERS

This chapter describes the motivation, methods, main results and conclusions of the seven main papers in this thesis.

2.1 Sediment compaction and overpressure (Papers 1 & 6)

2.1.1 Overpressure versus porosity relationship

Motivation for the paper "The lack of relationship between overpressure and porosity in North Sea and Haltenbanken shales" (*Marine and Petroleum Geology*, 1999):

Pore pressure estimates in shales are commonly based on indirect methods that again are based on the concept that overpressured shales have elevated porosities due to undercompaction.

Methods:

Log data (density and sonic velocity) from 101 overpressured and normally pressured wells in the Haltenbanken area and in the North Sea were analysed. Averaged log values for each of the Jurassic intra-reservoir shales at Haltenbanken (Not and Ror formations) and for each of the Cretaceous and Tertiary caprock shales of the North Sea (of Oligocene and Eocene age, as well as from Balder, Sele, Lista, Jorsalfare, Kyrre, Sola and Åsgard formations) were converted to shale porosity units according to equations given in the paper.

Main results and conclusions:

The porosity of the massive North Sea caprock shales and the porosity of the intra-reservoir shales at Haltenbanken do not differ significantly between overpressured and normally pressured formations. These observations strengthened our scepticism regarding the validity of overpressure vs. porosity (fluid pressure vs. effective stress) relationships in

the two areas. Undercompaction as a mechanism for overpressure in these two areas thus appears to be incorrect, as the overpressured formations do not exhibit elevated porosity.

We suggest that the high pore pressures are likely to have been generated after the sediments have been normally compacted, and / or that thermally controlled mineral reactions dominate the porosity reduction at temperatures and depth where diagenesis is quantitatively important (chemical compaction). We did not identify any overpressure mechanism that could explain a post-compaction source of the overpressures, and thus suggest that they resulted from diagenetic porosity reduction.

2.1.2 Geological constraints on pore pressure detection

Motivation for the paper "Geological constraints of pore pressure detection in shales from seismic data" (*Basin Research*, 2007):

Seismic methods for fluid overpressure detection in shales have become widespread in the oil industry. Such methods are largely based on the identification of anomalous seismic velocities, and on subsequent determination of pore pressures through relationships between seismic velocities and vertical effective stress. Although it is well known that lithology variations and compaction mechanisms should be accounted for in pore pressure evaluations, a systematic evaluation of these factors in seismic pore pressure prediction seems to be absent.

Methods:

Shale velocities from acoustic well logs were investigated in order to sort out the influence of lithology variations and compaction mechanism on the velocities. The analyses were performed on 104 wells in total: 80 wells from the northern North Sea and 24 wells from the Haltenbanken area. The analysis involved identification of large-scale density and velocity variations that were unrelated to overpressure variations.

Main results and conclusions:

Generally, we conclude that the success of pore fluid pressure detection from reflection seismic data depends on how well the influence of fluid overpressures on acoustic velocities is understood. In the simplest case, when rocks have compacted mainly mechanically, overpressures should coincide with abnormally high porosities. As mechanical compaction is favoured in shallow sediments and sediments that have undergone rapid burial, methods for seismic pore pressure prediction should have the best success rate here.

Specifically, we conclude that pore pressure prediction based on the undercompaction principle does not work in the investigated areas. However, conditions or exceptions occur: (1) where overpressured shales are characterized by low velocities, although their porosities are not anomalously high, as for the shaly Not Fm at Haltenbanken (to date, the processes that result in reduced velocities in some overpressured shales are not well understood.), (2) where overpressure build-up approximately coincide with the onset depth of smectite layers, as for the smectite-rich strata of Oligocene and Eocene age (both strata are characterized by low densities and low sonic velocities, irrespective of the pore fluid pressure).

Our study demonstrated the importance of performing a geological analysis as an integrated part of pore fluid pressure evaluation work. This is often neglected, and mechanical compaction is frequently assumed with little or no justification. As a result, seismic pore pressure predictions are often not very reliable.

2.2 Seismic characteristics of fluid leakage (Papers 2 & 3)

2.2.1 Caprock integrity in the western Haltenbanken area

Motivation for the paper "Evaluation of caprock integrity in the western (high-pressured) Haltenbanken area – a case history based on analyses of seismic signatures in overburden rocks" (*Norwegian Petroleum Society, Spec. Publ.*, 2002):

A significant number of exploration failures on the Norwegian Continental Shelf are due to hydrocarbon leakage. An improved understanding of migration and leakage mechanisms and processes in the subsurface is therefore crucial for prospect evaluation. The occurrences of zods (zones of deteriorated seismic signals) have previously been used to identify hydrocarbon leakage. However, since the causes of zods are not fully understood, no appropriate criteria appear to exist in order to distinguish between dry structures (due to fatal leakage), under-filled structures, and hydrocarbon-bearing structures.

In particular, the interpretation of zods in areas with high pressures and high prospect risk – such as the western part of the Haltenbanken area – has been associated with great uncertainties.

Methods:

A regional 2D dataset and a semi-regional 3D dataset were assessed to identify seismic anomalies of fluid leakage. Initially, we re-visited an earlier systematic evaluation of the 2D dataset across the Haltenbanken area that had resulted in six classified zods groups based on confidence and intensity. A modification of this classification into only two groups was made; strong zods vs. weak zods.

Main results and conclusions:

A separation of the zods emerged from the 2D data. The evaluation revealed a larger frequency of zods on the 2D dataset in the western leaky high-pressured Haltenbanken area than in the eastern normally pressured area.

All five of the investigated high-pressured exploration failures were associated with strong zods on the 2D data. The Kristin structure, however, also located in the high-pressured area, displayed only a weak dim-zone on the 2D data.

Re-evaluation of the different zods frequencies between the western and eastern Haltenbanken area – this time on the 3D dataset - revealed no such differences. This may be a result of the more accurate velocity analyses that are performed on 3D data.

2.2.2 Seismic characteristics of fluid leakage

Motivation for the paper "Seismic characteristics of fluid leakage from an underfilled and overpressured Jurassic fault trap in the Norwegian North Sea" (*Petroleum Geoscience*, 2004):

Identification of leakage positions would be useful in pre-drill assessments of hydrocarbon column heights. An investigation of the seismic signatures in the overburden post-rift sediments of a selected discovery well (Well 35/10-2) was done in order to try to identify diagnostic criteria for vertical oil/gas leakage from seismic data. This particular discovery was selected because the trap is underfilled and had experienced flexuring - and therefore was presumed to have leaked by shear failure. The structure is covered by high quality 3D seismic data.

Methods:

Evidences for vertical leakage were searched for in the 3D dataset. The method consisted of selecting lines which followed; (a) the top of the reservoir at the depth of the gas-water contact, and (b) the faults that delineate the structure. The lateral extent of zods in the overburden rocks was interpreted from average reflection strength maps.

Main results and conclusions:

A zone of deteriorated seismic signals was detected in the overburden above a triple fault intersection, of which two of the faults delineate the underfilled structure. This zod signal was interpreted as an indication of hydrocarbon leakage.

We concluded that hydrocarbon column height of the structure is most likely restricted by this leakage position, and not by the spill point of the structure itself (which is deeper). Shear failure, combined with high fluid pressures, was probably the mechanism for leakage of this structure.

Seismic signatures like those observed in the overburden of the 35/10-2 structure are proposed as recognition criteria for hydrocarbon-water contacts also elsewhere, although

such signatures can arise from causes other than fatal leakage. Hydrocarbon leakage identification should therefore be supported by other seismic indications of hydrocarbon presence before beeing assigned significant weight influence in hydrocarbon prospect evaluation.

2.3 Caprock membrane seals (Papers 4, 5 & 7)

2.3.1 Capillary resistance and trapping of hydrocarbons

Motivation for the paper "Capillary resistance and trapping of hydrocarbons: A laboratory experiment" (*Petroleum Geoscience*, 2005):

The concept of water flow through an oil-saturated reservoir and further through a water-saturated membrane caprock had not been experimentally tested. Thus, both the existence of a continuous water phase and the permeability of the water phase were not known. A laboratory experiment was performed to resolve these issues.

Methods:

Water in a completely water-saturated sandstone plug, attached to a semi-permeable porous membrane, was displaced by oil (0.5 MPa oil pressure) to a residual water condition (S_{wi}). The core holder was then oriented to simulate an oil reservoir with an overlying caprock and the excess oil pressure was removed. A differential pressure of 0.5 MPa was then applied across the water phase. Water was supplied to the core holder and the plug through the lower inlet. We wanted to see if water was the only phase that came out of the outlet side of the membrane, and if so, what the permeability of this water would be. To my knowledge, this type of experiments has not been performed previously.

Main results and conclusions:

Water flowed through the membrane (attached to the core plug) by the imposed pressure, whereas oil was kept in the core plug by capillary forces. Accordingly we concluded that the water phase is both continuous and mobile.

The permeability of the residual water turned out to be significantly higher than the permeability of a caprock shale (typically $10^{-2} - 10^{-5}$ µD), implying that residual water permeabilities within highly permeable and oil-saturated sandstones are sufficiently high to allow near hydrostatic pressure gradients in the water phase of moderate oil columns. With such external conditions, overpressure in the water phase will not promote capillary leakage of the hydrocarbon phase.

2.3.2 Relative permeability to wetting-phase water

Motivation for the paper **"Relative permeability to wetting-phase water in oil reservoirs"** (*Journal of Geophysical Research*, 2006):

The experiment reported in Paper 4 was initially only conducted on one highly permeable sandstone plug. The relevance of the experimental result to less permeable rocks remained uncertain. The general concern about the permeability to wetting-phase water, varying capillary pressures (i.e. hydrocarbon column heights), and accordingly the significance of reservoir overpressures to hydrocarbon exploration were therefore not fully addressed in Paper 4.

Methods:

The experimental setup and procedure of multiple experiments – conducted on three different core samples (Bentheimer 1990 mD, Berea 22.6 mD and Morvin 0.06 mD) – was identical to the setup for the experiment reported in Paper 4. This time, multiple capillary pressure experiments were performed on each sample. In total, nine new experiments were carried out.

Main results and conclusions:

Several laboratory experiments, performed on water-wet and oil-saturated sandstone plugs, demonstrated that water could flow through the samples and further through the ceramic

membrane, whereas the oil was retained in the sample by capillary forces of the hydrocarbon sealing membrane.

The experiments were performed on rock samples with permeabilities ranging from 0.06 mD to 1900 mD, and with capillary pressures ranging from 1.5 bar to 10 bar. The water flow likely migrated in acute corners and crevices of the pore network that were inaccessible to the non-wetting oil phase. The relative wetting-phase water permeability relates to capillary pressure, core permeability, and core porosity by:

$$\log k_{rw} @ S_{wi} = -1.75 \log(P_c \sqrt{(k/\phi)}) - 1.95$$

The analyses demonstrated that the calculated overpressure drops in the water phase of oil reservoirs are generally insufficient to influence the capacity of good membrane caprocks. However, column heights sealed by inferior membrane caprocks may be significantly reduced in the presence of reservoir overpressure.

2.3.3 Membrane seal leakage

Motivation for the paper **"Membrane seal leakage through establishment of oil-wet flow paths"** (*Subm. Geology*):

To examine the implications for hydrocarbon sealing of some recent research results that address wettability alterations and pore scale fluid flow in the presence of capillary sealing. This examination leads us to suggest modifications to the current models of capillary sealing and leakage through membrane seals. Based on these suggestions, we re-examine the issues of oil residence time and oil saturation in membrane caprock shales.

Methods:

Two lines of research – one focusing on improving the understanding of fluid flow within reservoirs and the influence of fluid overpressures on hydrocarbon leakage, and one addressing wettability changes - provided a basis for a refined model for oil leakage on a pore scale level through caprock shales.

Main results and conclusions:

It is suggested that capillary sealing of oil is a geologically short-lived phenomenon, and that oil-wet flow paths will be established through caprocks as a consequence of vertical water leakage up through oil columns and further through caprocks. This model is consistent with laboratory experiments on wettability changes and membrane sealing on a pore scale. The model predicts that membrane leakage replaces capillary sealing much more efficiently than what would be the case if wettability changes were rate-limited by diffusion of crude oil compounds into caprocks. The model seems to be consistent with the reported dynamic nature of oil pools, the lack of high oil saturations in non-fractured caprock shales, and the abundance of high gas concentrations in caprocks above hydrocarbon reservoirs.

3. OVERALL CONCLUSIONS AND IMPLICATIONS

This dissertation was motivated by the realization that four concepts, which are too simplistic, are widely assumed in the petroleum industry:

First, mechanical compaction and associated disequilibrium compaction are frequently assumed to be the main mechanism for overpressure formation, although data are rarely given to support this assumption. This thesis concludes that neither the North Sea nor the Haltenbanken shales compacted mechanically at moderate to deep burial. Therefore, high overpressures in these rocks were not caused by disequilibrium compaction, but more likely by diagenetic processes that were largely unaffected by fluid pressures. Traditional seismic and log-based pore pressure detection methods in these areas should be expected to result in under-prediction of fluid overpressures because the porosities are not higher in overpressured shales than in normally pressured shales.

Second, observations of zods (zones of deteriorated seismic signals; at times termed gas chimneys) are often interpreted as evidence of hydrocarbon leakage. This thesis concludes that the occurrence of zods may identify hydrocarbon leakages and where pressure compartments leak. However, prior to interpreting these zones as hydrocarbon leakage, the interpreter must be aware of the various geological processes and non-geological origins that could cause such velocity variations: (a) hydrocarbon leakage, (b) leakage of water with dissolved gas (that could create an inhomogeneous gas saturation), (c) fault or fracture zones themselves, (d) fluid leakage above fault(s) or fault junction, or (e) data quality issues. As a result, applications of zods in hydrocarbon prospect evaluation should be performed more carefully than what is often seen in the industry today.

Third, the consequences of high overpressures are often assumed to be hydrocarbon leakage through the caprock – either because of hydro-fracturing or because high water pressure force oil or gas through membrane seals. This thesis concludes that high overpressures are compatible with hydrocarbon preservation. Vertical water leakage from the apex of a trap may take place while oil and gas are retained by capillary forces within the structure. This result is consistent with the fact that several of the largest oil fields on the Norwegian Continental Shelf (Statfjord, Gullfaks, Snorre, Visund, and Kvitebjørn) are highly overpressured and leaky, and yet contain vast amounts of oil and gas.

Finally, vertical leakage is often assumed to occur as separate phase oil flow through water-wet caprock shales, and membrane seals will, according to the definition of capillary entry pressure, preserve oil indefinitely as long as the critical pore throats are sufficiently small. This thesis concludes that residual water, which flows through reservoirs and caprocks, carries polar compounds that locally change the caprock wettability, thus resulting in the formation of oil-wet flow paths. This suggestion explains how pore-scale migration can take place through caprock shales without resulting in extensive oil saturation in these shales. The suggestion further implies that membrane seals deteriorate with time, thus promoting the transient nature of oil pools that are observed, but that are not compatible with endless membrane sealing time.

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