Determination of overpressures in sandstones by fluid flow modelling: the Haltenbanken area, Norway: Reply

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Introduction

In my paper (Nysæther 2006) on the development of overpressures in Haltenbanken, I sought to understand the geological principles that govern the distribution of these pressures. I introduced a physical model that was capable of explaining this in general terms. This model was based on the Darcy formula for fluid flow and demonstrated how overpressures in sandstones may be interpreted as being a direct consequence of compaction-generated overpressures in the surrounding shale. This paper has generated a discussion from Bjørlykke (2006), which I shall respond to below. I shall, however, first try to explain the principles behind the model.

Figure 1a (left) shows a sandstone body that slopes through a shale sequence from the surface down to 5000m depth. Figure 1b (right) shows the state of overpressure in the rocks. Since the sandstone is exposed at the surface the pore water will show hydrostatic pressure (i.e. no overpressure) provided it has retained an appreciable permeability all along its course. The right side of the same figure shows how compaction, with accompanying low permeabilities, will increase the shale overpressure with depth. This is in line with the situation I have observed in Haltenbanken. Figure 2a (left) shows a situation where a horizontal and sealing fault offsets the sandstone in such a way that the lower part of the sandstone is isolated from its upper part. Figure 2b (right) shows how the pore pressure in the lower sandstone body will develop with time. While the upper sandstone body will retain its hydrostatic pressure, the lower part will be exposed to the pore pressure of the surrounding shale, which is appreciably higher than the original hydrostatic pressure in the sandstone. As the pore water in sandstone 2 no longer has a possibility of escaping to the surface the incoming water will increase the pore pressure in the sandstone. The vertical lines show how the pore pressure will increase with time, fast at first but slowing down

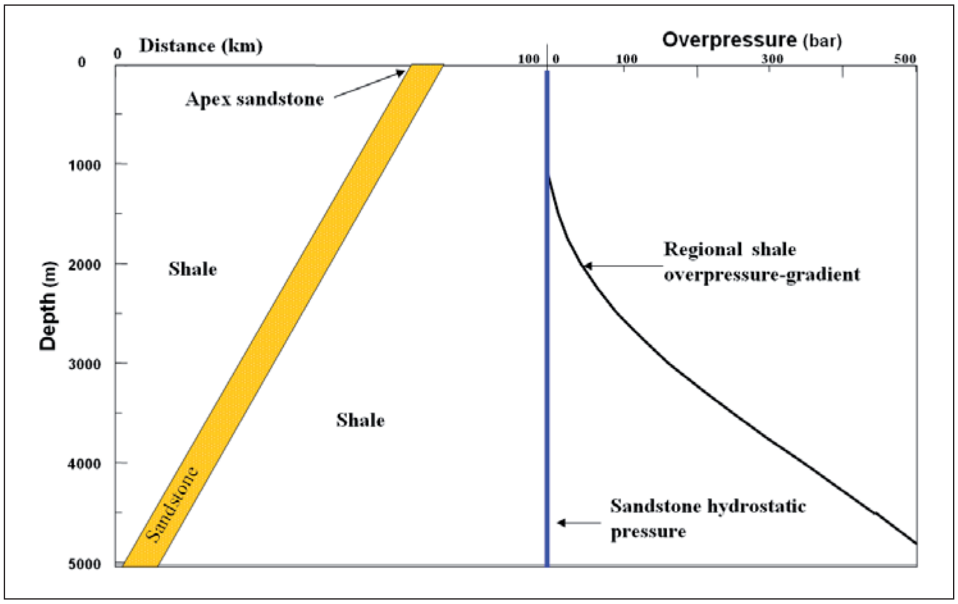

Figure 1. Cross section used to exemplify the pore pressure distribution (right) in a simple sandstone/shale system (left).

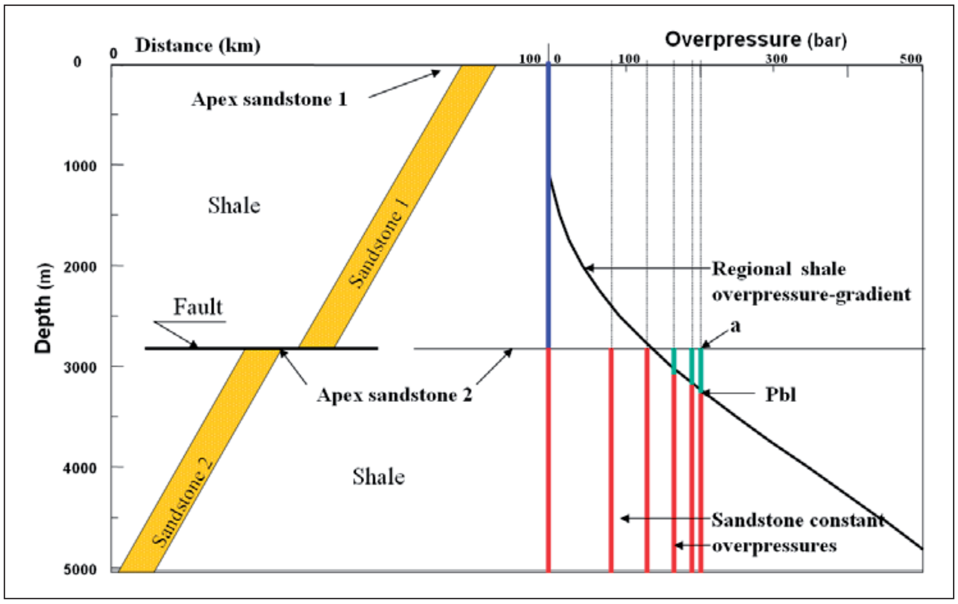

Figure 2. The sandstone in the cross section in Figure 1 has been offset by a horizontal fault (left). The inferred pore pressure development in the system is shown to the right.

as the differences in overpressure decrease. As the top (apex) of the sandstone attains the regional shale pressure gradient, water will start flowing out of the sandstone at the apex, and this flow will increase and include deeper levels as the overpressure in the sandstone increases. When position **a** is attained the amount of water which enters into the sandstone below the point of intersection (the pressure balance level, pbl) between the shale gradient and the sandstone, equals the amount of water that is expelled above the pbl. At this point, a situation of mass balance has been attained and the pressure in the sandstone will show no further increase. The sandstone may now be termed a pressure cell. If faults (or sandstone pinch-outs) occur at different depths, the different apexes will follow a line (apex gradient), which parallels the shale pressure gradient. A plot of the apexes of mapped pressure cells in Haltenbanken has verified the existence of such a gradient (Nysæther 2006). The fluid flow model, which has been described in my paper (Nysæther 2006), is capable of calculating a theoretical apex gradient as a function of the measured regional shale gradient, with the shale permeability gradient regarded as the most important variable parameter. The apex gradient can be used as a means of making a prognosis of the pore pressure in a reservoir before drilling, or, if the pore pressure is known, of identifying the depth to the apex of a reservoir.

Discussion.

Bjørlykke (2006) questions the validity of the shale pressure gradient with respect to both its existence and its linearity with depth. The pressure gradient in the shale is indeed linear below approximately 2500m as evidenced by pressure measurements in thin sandstones of the Cretaceous and Upper Jurassic section. However, the existence of a linear gradient is accidental and is no prerequisite for the validity of the model. Further, I do not concur with Bjørlykke's statement that the regional shale pressure gradient is hypothetical. Figure 3 shows that the pressure measurements in four of the plotted wells (6506/11-2, 6507/2-2 and -3 and 6507/7-1) could be considered as representing pressure gradients within the shale and that these gradients compare satisfactorily with the regional gradient. These four wells, which are the only wells with pressure measurements at several levels in the Cretaceous section, are situated up to 100 km apart. The overlapping character of the pressure gradients from these four wells attests to the regional character of the shale pressure gradient.

In Nysæther (2006) I concluded that the flow of water in response to compaction would normally be upwards. Since the bedding planes in the area are sub-horizontal, the flow would consequently run approximately perpendicularly to the bedding. Bjørlykke (2006) argues that as the permeability parallel to the bedding frequently is much higher than perpendicularly to the bedding, fluid transport in that direction could be favoured. Fluid flow, however, is also a function of the pore pressure gradient in the rocks. If the flow of fluids in Haltenbanken was mainly horizontal a decrease in overpressures along the lines of flow should reveal this fluid movement. Normally, a flow of this nature would be from the centre of the basin towards its flank. From Figure 3 we see that the pressure differences at a depth of approximately 3500m between Smørbukk (6506/11-2), which is situated fairly centrally in the basin (Figure 4), and wells 6507/7-1 and 6407/1-3 (Tyrihans), which are more in flank positions, are of the order of 10–15 bar. This gives a horizontal pressure gradient between Smørbukk and well 6507/7-1 (red line = 50 km) of 0,0002 bar/m and between Smørbukk and Tyrihans (blue line = 26 km) of 0,0006 bar/m. Notice that the direction of horizontal flow in the latter case, if it existed, would be from Tyrihans and towards Smørbukk

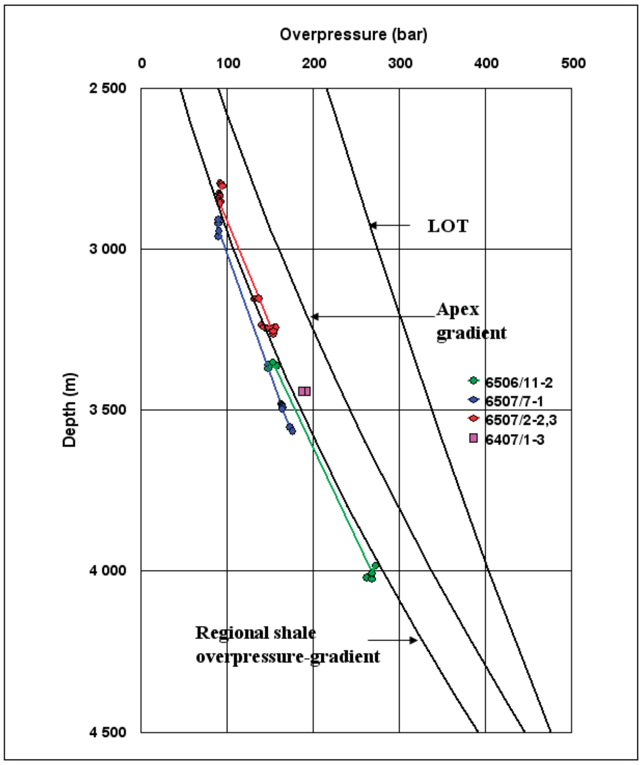

Figure 3. Overpressure vs. depth plot from the four wells that display measurements at two or more levels in the Cretaceous section. Notice the good correlation between the overpressure gradients in the wells and the regional shale overpressure gradient. Also shown are the overpressures in well 6407/1-3 (Tyrihans), which have been used as a basis for calculating one of the horizontal overpressure gradients.

i.e. from the flank towards the centre of the basin! As a comparison, the vertical pressure gradient in the shale is about 0.2 bar/m. We see that in both instances the horizontal gradient is negligible relative to the vertical gradient. Over the same distances the average slope of the Lange Formation is about 0.5° and 1.2°. These numbers attest to the sub-horizontality of the formations in Haltenbanken. If permeability anisotropy existed in the shale, as claimed by Bjørlykke (2006), and if lateral flow is to be important, this anisotropy should be of the same order as the pressure gradient anisotropy. This means that permeability anisotropy of a few hundred to a thousand would be needed. According to Clennell et al (1999) the permeability anisotropy in consolidated natural clay is typically between 1.1 and 3. Higher levels of anisotropy may exist and "values >10 that are known to exist on the formation scale are produced by strong contrasts between the permeabilities of interlayered beds" (Clennell et al 1999). However, as the clays and siltstones of the Melke Formation are highly bioturbated (core information, Norsk Hydro internal reports) the permeability contrasts between interlayered beds are probably < 10. It therefore seems unlikely that the permeability anisotropy would attain levels that support lateral flow. We cannot exclude, however, that locally and in steeply dipping shale beds the pressure gradients would favour lateral flow. But on the whole, and averaging out differences in shale bed orientation and local flow of water through isolated sand bodies on a basin scale, it seems that the pressure gradients recorded favour vertical flow.

To answer the question of the permeability of shale I must reiterate that it is the permeability of the *adjacent* shale and not the permeability of the *basin* shale that enters into the calculations of fluid flow. Also, as stated in my paper (Nysæther 2006), it is not the absolute permeability but rather the permeability gradient that is of importance. The permeability gradient reflects the effective permeability perpendicular to the bedding across all or parts of the adjacent shale. The permeability of the basin shale is of no concern in this respect because it does not enter into the calculations. The permeability of the basin shale is, however, reflected in the regional shale pressure gradient. If the permeability gradient in the basin shale shows a non-linear behaviour with depth, this would then be revealed by the shape of the pressure gradient, which would show a similar departure from linearity.

The adjacent shale that was investigated in this work is the basal shale and siltstone of the Melke Formation. Since this was deposited under fairly constant environmental conditions there is all reason to believe that the original clay mineral suite would be relatively constant all along the extent of this formation. Compaction of such a unit would then probably give a regular decrease in both

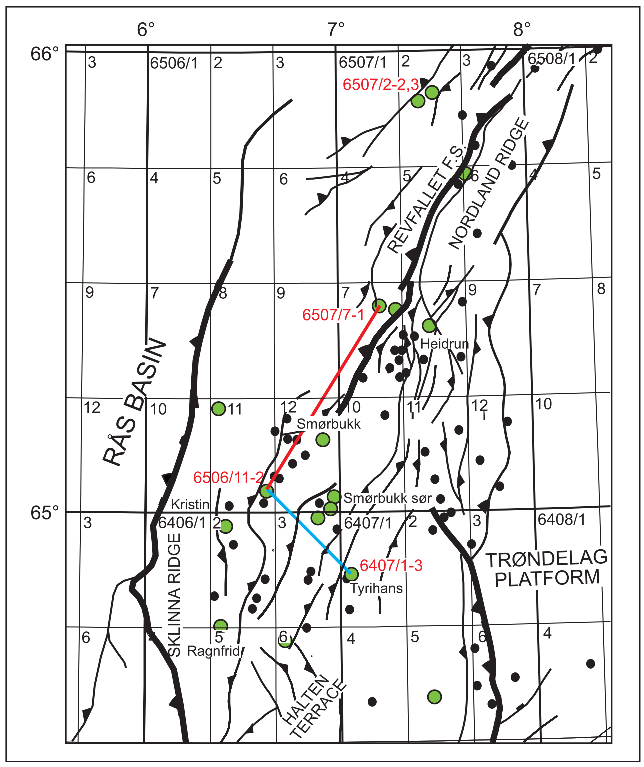

Figure 4. Location of wells with pore pressure measurements (green dots). The outlined well numbers in red refer to wells with pressure measurements at two or more levels in the Cretaceous section. Horizontal gradients of overpressure have been determined along the red and blue lines.

porosity and permeability with depth. We cannot exclude, however, that diagenesis would modify both the porosity and permeability below certain depths. If, for instance, the permeability below 4000m (Table 1, Nysæther 2006) is lowered by one order of magnitude this would lower the theoretical apex by 80m. While this of course is an important figure it should be realized that the other apexes would be lowered by an amount of the same order. This would have necessitated a recalculation of the apex trend based upon a new and different permeability gradient. This new permeability gradient would then be taken as the real gradient for the Melke Formation. The permeability gradient is essential in order to make a correlation between the theoretical and the calculated apex of the sandstones modelled. The gradient used in my paper (Nysæther 2006) does not deviate much from several other published gradients as can be seen from Figure 18 (Nysæther 2006), and hardly qualifies to be termed "unrealistic".

Fortunately, in order to arrive at a figure for the position of the apex we do not need to know anything about the absolute permeability of the adjacent shale. A correct value of the absolute permeability is necessary only if there is a need to calculate the real fluid flow in and out of the sandstones. The flow figures arrived at must therefore be regarded as preliminary and are included in order to show the potential of this fluid flow model.

Bjørlykke (2006) argues that the flow of water through a hydrocarbon filled reservoir could remove "much of the most soluble hydrocarbons such as methane and benzene". This is an interesting argument, as under "normal" reservoir conditions (pore pressure=350 bar, temperature=120°C and water salinity = 30.000 ppm) one cubic meter of water could contain 3m^3 of dissolved natural gas (Burcik 1996). If these values were applied to the example shown in Table 1 (Nysæther 2006), there would be an outward flow of water averaging 2m^3/Ma (0.002liter/a) for each m^2 surface. The loss of gas through the roof of a hydrocarbon filled reservoir covering for instance 100 km^2 would then be 600*10^6 m^3/Ma. A field covering this surface area and containing at the outset 120*10^9 m^3 gas would consequently have been emptied in the course of 200 Ma. In the example given, the permeability at the chosen depth was arbitrarily set in the order of 10^{-21} m^2. If this were changed to 10^{-20} m^2 (alternatively 10^{-22} m^2) it would take 20 Ma (2000 Ma) to empty the reservoir. The last two examples used the same permeability gradient as in the first example. Most publications that I have read use lower permeabilities at the depths covered by the example in Table 1 (Nysæther 2006) than those in my calculations. The use of such low permeabilities would *lower* the loss of light hydrocarbons relative to the figure given by me. This means that Bjørlykke's view in this case is rather pessimistic, but the point is well made. It should be remembered though, that an outward flow of water only applies to reservoirs that are positioned *above* the pbl. *Below* the pbl the flow of water would be from the shale to the sandstone implying no loss of dissolved hydrocarbons.

Bjørlykke (2006) also argues against the use of a constant pressure difference between the shale and the reservoirs in my model. I underlined (Nysæther 2006), however, that my model was based upon the principle of steady-state flow in which the conditions at each point in the system are constant with respect to time. I further disagree with Bjørlykke that "the rate of compaction in the adjacent shale is rate limiting for the flow into the sandstones, not the pressure gradients or the permeability". In my view compaction and permeability are mutually dependant on each other. It is true that compaction will reduce the permeability of shale and thus reduce the flow of fluids. However the reduction in permeability will at the same time reduce the compaction by hindering the escape of fluids from the shale. Whether the fluid flow will increase or decrease with time is therefore mainly a function of the sedimentation rate at the sediment – water interface, which will influence the compaction, and the permeability of the shale, which will influence to what degree water is expelled from the shale. The difference in opinion on this subject is probably caused by our different views on the role that chemical compaction plays during the compaction process. Let me exemplify my view with the kaolinite-illite transformation process. At Haltenbanken the amount of kaolinite decreases and the amount of illite increases sharply in sandstones between 3700m and 4000m (120-140°C) (Bjørlykke 1998). This is thought to be a consequence of the kaolinite to illite transformation according to the formula: K-feldspar + kaolinite = illite + quartz + water (Bjørlykke 1998). The mineral reactants of this reaction will have the same volume as the mineral products (Osborne and Swarbrick 1999). Therefore, in this case chemical compaction will not change the volume of the rock. Unfortunately, the kinetics of this reaction is not precisely known, but the reaction is thought to be mainly time and temperature and not pressure dependent (Bjørlykke 1998). If we assume that the original volume of kaolinite in the Melke shale is 15% and the reaction takes place over the depth/temperature range given above, an average of 0.5% of the rock would be transformed by chemical compaction for each 10m lowering of the sediment. In my view this means that 99.5% of the rock would still be compacted by mechanical compaction over the first 10m interval, and so on. If this process goes to completion, the shale would have lost all of its original kaolinite and added a similar amount of fibrous illite. Still around 85% of the rock is more or less unaffected by the process and would consequently be exposed to mechanical compaction. The diagenetically formed illite will also be exposed to the forces of gravity and compact mechanically. However, due to the different crystallographic form of the two minerals (blocky vs. fibrous) they will most likely compact differently. This may have a permeability reducing effect on the rock (Bjørlykke 1998). On the other hand, released water from the transformation process would probably lead to a slight and simultaneous increase in the pore pressure of the rock. These two processes may therefore to a certain degree counteract each other in the fluid flow equation. Quartz is another by product of the kaolinite-illite transformation and will most likely be precipitated as grain coatings on clastic grains of quartz. However, since clastic grains in shale normally are not in contact, the grain coatings will probably have no cementing effect. We may therefore say that the diagenetic reactions referred to above have brought about some textural modifications in the rock, and as more and more of the kaolinite is transformed to illite, the character of the compaction process will slowly change. However, the compaction process will most likely still be dominantly mechanical and create the driving force that makes fluids flow.

Bjørlykke's (2006) Figure 1 is hard to interpret because he combines a two dimensional lithology scheme with a pressure-depth diagram. However, I read the figure and the corresponding text to indicate the existence of an apex gradient that is close to the LOT-gradient (fracture gradient), and that an excess fluid pressure in the sandstone is thus capable of fracturing the roof. I take this as an indication that he proposes this mechanism to be responsible, wholly or in part, for the pressure situation in Haltenbanken. It is therefore surprising that he states that "while the degree of overpressures in the northern North Sea seems to be controlled by the present day fracture pressure estimated from the Leak Off Tests (LOT) the overpressure in many Haltenbanken reservoirs may be considerably lower". A glance at my Figure 3 also shows this to be true. Bjørlykke's comments on this issue have therefore no relevance for the situation at Haltenbanken. He further states, "The main control on the pressures in Haltenbanken reservoirs is the degree of lateral drainage maintaining nearly hydrostatic pressures in the Smørbukk Field and other fields east of the Klakk fault and overpressures in the reservoirs on the western side of this fault complex". He refers here to two publications in which he is co-author (Olstad et al 1997; Karlsen et al 2004). The Smørbukk Field was also used as an example in my paper (Nysæther 2006), where I found the pressure situation in and around this field to be very much in line with the results of my model. Thus we have opposing views on the cause of the pressure difference across the Klakk fault. Bjørlykke favours a lateral drainage of fluids across the fault. My model calls for an essentially vertical movement of fluids paralleling the fault. However, neither of us can claim to have the correct answer.

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Erratum:

Nysæther E.: Determination of overpressures in sandstones by fluid flow modelling: the Haltenbanken area, Norway. *Norwegian Journal of Geology 86*, 1-27.

Appendix: There appears a typographic error in the polynomial-fit equation for the regional shale-gradient (1): The equation should read: $P = - 21.34338 - 0.05385Z + 3.23265\ (10^{-5})\ Z^2$.

I would like to thank Dr. Mark Pay of Faroe Petroleum Norge AS for bringing this error to my attention.