Diagnosing high-porosity sands for reservoir characterization using sonic and seismic

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Summary

At high porosity, velocity in reservoir rocks strongly depends on the position of the intergranular material. Velocity is high if the original grains are cemented at their contacts. It is low if the pore-filling material is placed away from the contacts. In the latter case we have truly unconsolidated sediments. In the former case we have high-porosity cemented rocks. Separating these two rock types is important for hydrocarbon identification. Due to the difference in the rock frame stiffness between the unconsolidated and high-porosity cemented rocks, seismic signatures of the former filled with water can be very close to those of the latter filled with hydrocarbons. This may complicate direct hydrocarbon detection. We separate the two rock types by diagnosing sand using rock physics theory. We conduct such diagnostic on well log data from two wells that penetrate the Heimdal formation (North Sea). We show that the Heimdal formation reservoir is composed of both unconsolidated and cemented high-porosity sands. The initial quartz cementation present in the latter is clearly seen in the cathode-luminescent SEM images. These images, combined with point XRD analysis, confirm our diagnostic that the high-velocity high-porosity sands in Heimdal contain quartz grains surrounded by quartz-cement rims. We find that the two different types of sand which are capped by similar low-impedance shales produce drastically different AVO signatures. The oil-filled high-porosity cemented sand shows a relatively strong zero-offset reflectivity which becomes less positive with increasing offset, while the oil-filled uncemented sand shows a negative zero-offset reflectivity with increasingly negative far-offset response. These results show that (1) rock diagnostic can be conducted not only on the log scale but also on the seismic scale; and (2) taking into account the nature of the rock improves our ability to identify pore fluid from seismic.

Introduction

Quartz cementation of sands greatly affects porosity, permeability, and seismic properties. Sandstones in continuously subsiding sedimentary basins, such as in the North Sea and the Gulf Coast, tend to have poorly developed quartz cement down to a depth of 2.5 - 3.0 km (Bjørlykke and Egeberg, 1993). Hence, Tertiary sands in the North Sea are usually reported to be poorly consolidated with no (or insignificant quantities of) quartz cement. "Insignificant" is related to volume -- small amounts of quartz cement do not significantly affect porosity. However, only small amounts of cement at grain contacts are needed to considerably stiffen the frame of a rock (Dvorkin and Nur, 1996) and strongly increase velocity. We apply the contact cement concept to study two clean sandstone intervals, both representing the Palaeocene age Heimdal Formation in the North Sea. Both intervals are oil-filled reservoir sands of commercial interest. We diagnose the rock using well log measurements and rock physics theory. We assume that if in the velocity-porosity plane a datapoint falls close to a theoretical line, the internal structure of the rock is similar to the idealized structure used in the model. We find from such diagnostic that one interval is composed of unconsolidated sand, while the other interval is composed of cemented high-porosity sand. Thin-section and SEM images confirm this diagnostic. By studying the seismic signatures of these two different types of clean sands we upscale the log-based diagnostic to the seismic scale.

Rock diagnostic and confirmation

We examine two wells -- Well #1 and Well #2. Sonic velocity and gamma-ray are plotted versus depth for both wells in Figures 1a to 1d. Vp is plotted versus porosity in Figures 1d and 1f. Notice that in Well #2 a thick sand interval (gray bar in Figure 1c) is marked by extremely low and constant gamma-ray readings. This sand layer is surrounded by high-gamma-ray shale packages. In Figure 1f, these two lithologies fall into two distinctive velocity-porosity patterns. In Well #1, unlike in Well #2, we observe a gradual variation of clay content between very clean sand and shale. Only a relatively thin (10 m) sand interval (gray bar in Figure 1a) is identified as a practically clay-free reservoir sand. Because of the gradual variation of clay content in this well, we do not observe (Figure 1e) velocity-porosity patterns as distinctive as in Well #1. These two clean sand intervals (in both wells) represent the same stratigraphic level, although located in different oil fields. They are shown by bold black symbols in Figures 1e and 1f.

For the purpose of diagnostic, we plot together these two subsets of the data (Figure 2). We diagnose these rocks by superimposing theoretical rock physics curves (Dvorkin and Nur, 1996) on this plot. The contact cement line corresponds to the case where rock is formed by quartz-cement rims growing on sand grains. Here velocity drastically increases with only slightly decreasing porosity. The unconsolidated line corresponds to the case where porosity reduces not due to the growth of contact cement, but due to loose pore-filling material such as small grains, mica and detrital clay particles. Here velocity strongly depends on the effective pressure (about 20 MPa here) and only gradually increases with decreasing porosity. Notice that the Well #2 data points do not fall on the contact cement line. This is because the volumetric fraction of contact cement in these rocks, according to a thin section point-count analysis, is constant (about 2%) in the entire porosity range. Therefore this contact cement is responsible for the initial drastic velocity increase (as compared to uncemented sand) at 37% porosity, but the continuing porosity decrease is due to loose pore-filling material. This concept is represented by the constant cement fraction line that has the shape of the unconsolidated line, but a different high-porosity end member. The two sand intervals can be diagnosed by rock physics theory as: (a) Well #1 -- unconsolidated quartz sand; and (b) Well #2 -- contact-cemented quartz sand with a constant fraction of cement in the whole rock.

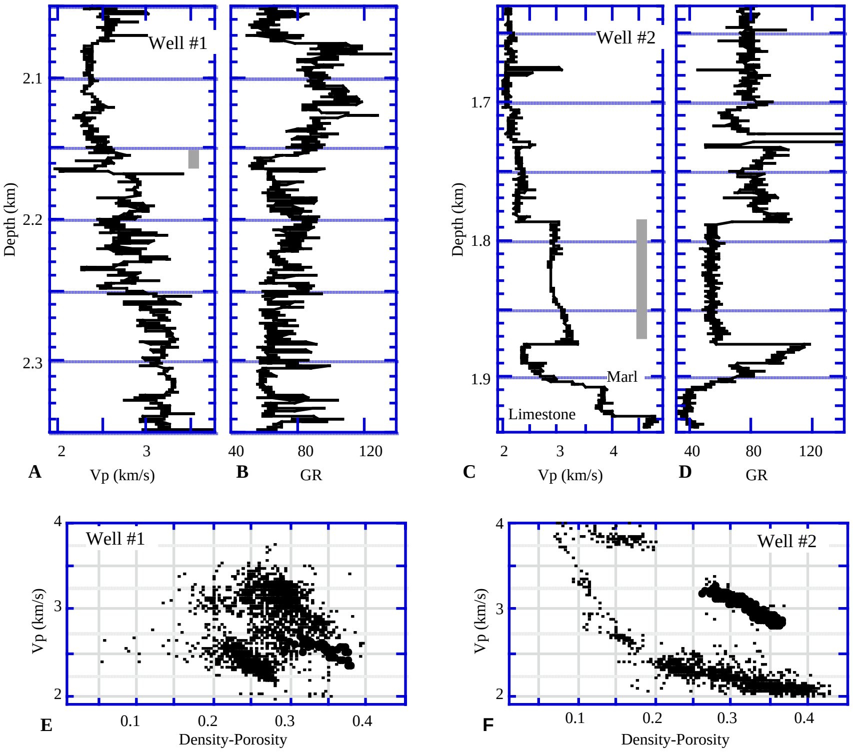

Figure 1. P-wave velocity and gamma-ray versus depth (a-d); and P-wave velocity versus porosity (e and f) for both wells.

To directly confirm this diagnostic, consider the thin sections of two samples from both intervals (Figure 3). The samples have approximately same porosity. They are predominantly quartz. No contact cementation is apparent in both images. The left image (Well #1) shows some organic coating around quartz grains. Consider now two SEM images of a sample from Well #2 (Figure 4). The left-hand image is in back-scatter light and the right-hand one is in cathode-luminescent light. Notice the V-shaped grain in the middle. No contact cement rim is apparent around this grain in back-scatter light. Cathode-luminescent light reveals a contact-cement rim around this grain. The point XRD analysis shows that both the grain and cement rim are pure quartz. This confirms our diagnostic that the Well #2 sand interval is contact-cemented. The hexagonal crystal shapes in the upper left corner also indicate diagenetic cementation. No cement rims or hexagonal crystal shapes have been found around grains in the sand interval from Well #1. Another direct proof of our diagnostic was that cores extracted from Well #1 appeared as piles of loose sand, whereas those from Well #2 supported external stress.

Seismic response

To understand how the type of sand (unconsolidated versus cemented) affects the seismic response, we analyze CDP gathers at the well locations. Figure 5a shows the real CDP gather at Well #1 where the picked horizon is at the top of the Heimdal formation. Figure 5b gives a synthetic CDP gather for this well produced by using a 30 Hz zero-phase Ricker wavelet and a logderived reflectivity series. Both the real and synthetic gathers show reflectivity increasingly negative with increasing offset at the picked horizon. This reflectivity is plotted versus offset (angle), together with the theoretical Zoeppritz line, in Figure 5e. Contrary to Well #1, the top of the Heimdal formation in Well #2 (which is capped by similar shales) produces a strong positive reflector with reflectivity decreasing with increasing offset (Figures 5c and 5d). For this well, the reflectivity is plotted versus offset (angle), together with the theoretical Zoeppritz line, in Figure 5f. The synthetic response is very close to the real data in both wells which means that we can rely on well-log-based rock diagnostic to predict seismic response.

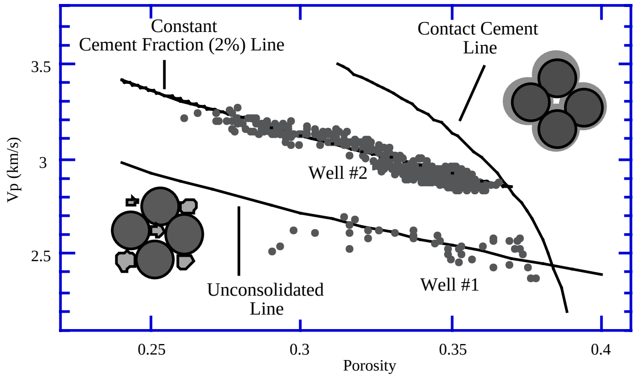

Figure 2. P-wave velocity versus porosity for sand intervals in both wells. Theoretical lines serve to diagnose the rocks.

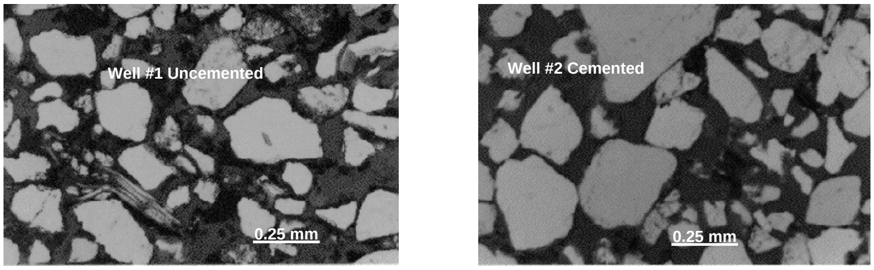

Figure 3. Thin sections of two selected samples from Well #1 (left) and #2 (right).

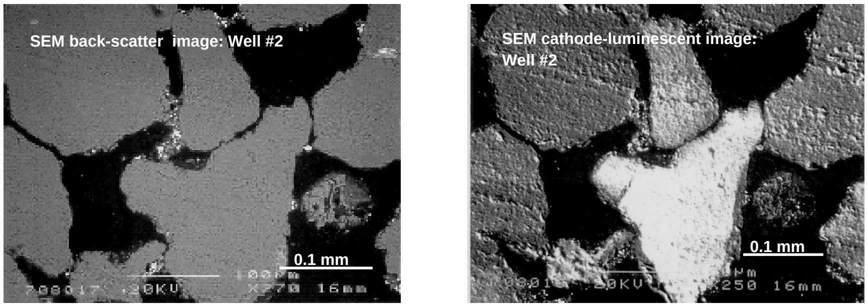

Figure 4. SEM images of a Well #2 sample in back scatter light (left) and cathode-luminescent light (right).

This offset-dependent reflectivity analysis shows that clean sands of the same formation, similar porosity, and with comparable oil saturation produce drastically different seismic response depending on whether they are truly unconsolidated or have initial quartz cementation. Therefore, we can use both normal-incidence and offset-dependent reflectivity to diagnose rock and characterize a reservoir from seismic. Such rock diagnostic may be of great importance because if high-porosity contact-cemented sands are not separated from truly unconsolidated sands, one may misinterpret a change in seismic signatures caused by this petrographic effect as a pore-fluid effect.

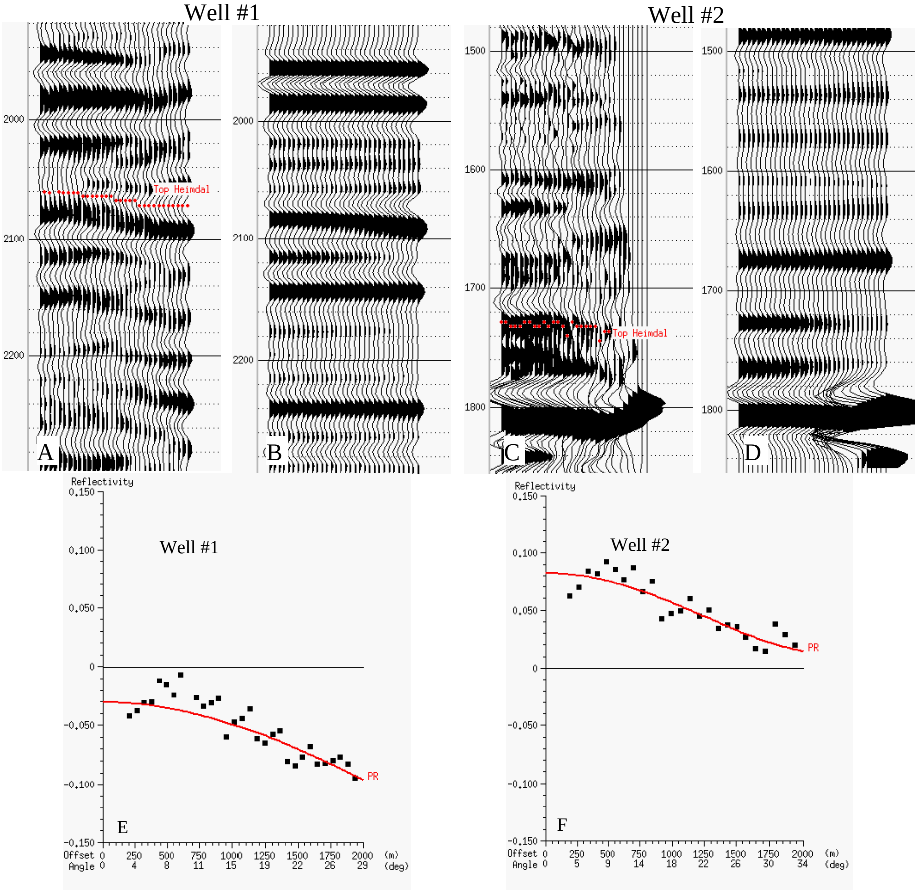

Figure 5. Top. Real (a and c) and synthetic (b and d) CDP gathers. In synthetic gathers, the AVO effect was modeled only at the target zones. Bottom. Real reflectivity versus offset and angle (symbols) and theoretical Zoeppritz lines

Conclusion

Rock diagnostic is important for correctly characterizing prospective reservoirs. Such diagnostic is based on rock physics theory and can be accomplished using well log data. The diagnostic features observed in well log data can be translated into distinctive seismic signatures. Therefore, seismic data can also be used for rock diagnostic given that the stratigraphic unit is resolvable at the seismic scale. In this paper we applied the diagnostic concept to the Heimdal formation, and were able to discriminate high-porosity cemented from unconsolidated sands both from well logs and seismic.

Acknowledgment

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References

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Sandstone diagnostic

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