Effect of petrophysical parameters on dispersion
from Frigg-Delta reservoir, North Sea

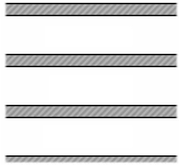
Introduction

Amplitude-Variation-with-Offset (AVO) is a technique that has been used often to identify seismic anomalies as hydrocarbon reservoirs. Although it has worked well in the past, it has some limitations; the attenuation is often neglected, it assumes frequency independent reflection coefficients and it gives little to no information on the porosity/saturation of the medium. The attenuation is not considered a large issue in conventional AVO studies as there are methods available that compensate for its effects. In the case of a frequency dependent reflection coefficient, attenuation plays a major role in its effects and can thus not be neglected.

A compressive wave, travelling through a saturated, porous medium develops a pressure gradient between the peak and trough of the wave. This pressure gradient causes wave-induced fluid flow (WIFF) – first introduced by Biot (1956a,b) – which, in turn, causes attenuation of the wave and the reflection coefficient to become frequency dependent.

One type of WIFF, local (mesoscale) flow – introduced by White (1975) and White et al. (1975) – arises due to heterogeneities on scales between the rock's grain size and the seismic wavelength. This local flow has been shown to cause significant attenuation in the seismic frequency band (Pride et al., 2004).

White's stratified layered model (White et al., 1975) aims to describe this attenuation. It defines partial saturation as two permeable, alternating layers in the reservoir rock, saturated with two different fluids, such as oil and brine. In this paper, we modeled, with respect to several important petrophysical parameters, the frequency dependency with the goal of evaluating the viability of estimating oil saturation from seismic data.



White's layered model of oil (colored) and brine (white) alternating layers.

Method

According to Carcione and Picotti (2006), the complex P-wave velocity, V, is acquired and used to calculate the phase velocity for each layer p,

$$V_p = [(1/V)]^{(-1)}, \quad (1)$$

and the quality factor,

$$Q = \frac{\mathrm{Re}(V^2)}{\mathrm{Im}(V^2)} \quad . \ (2)$$

The frequency dependent normal-incidence reflection coefficient (NI) and the phase angle (φ) are given by

$$|NI(\omega)| = \sqrt{\frac{\omega^2 (V_{P2p2}-V_{P1p1})^2+(V_{P1}V_{P2\,p1\alpha2})^2}{\omega^2 (V_{P2p2}+V_{P1p1})^2+(V_{P1}V_{P2\,p1\alpha2})^2}} \quad , \ (3)$$

$$\varphi(\omega) = \tan^{-1}\left(\frac{2\rho_2 V_{P1}\,\rho_1\,\omega\alpha_2\,V_{P2}^2}{V_{P2}^2\rho_2\omega^2-V_{P1}^2\rho_1^2(V_{P2}^2\alpha_2^2+\omega^2)}\right) \quad . \ (4)$$

Application

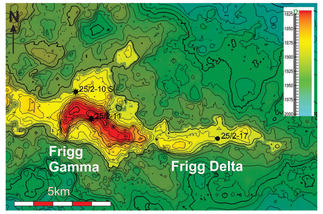


Figure 2: Time map of the Frigg formation with indication of wells. The color scale is in ms below sea level and the shaded coloring represents the area below the oil-water contact.

The chosen study area is the Frigg-Delta oil reservoir (Figure 1) in the North Sea, off the coast of Norway. The sandstones in the Frigg formation are of early Eocene age and we parameterized our model using well data from this proven oil reservoir. These parameters are shown in Tables 1 and 2.

Table 1: Fluid properties (K = bulk moduli, ρ = density, η = viscosity) of the Frigg formation sands.

Fluid	K [GPa]	ρ [kg/m³]	η [cP]
Water	2.74	1031	0.504
Oil	1.68	918	17

Table 2: Rock properties of the Frigg formation sands. V_p and V_s are the P- and S-wave velocities. ρ , Φ and κ are the rock densities, porosities and permeabilities, respectively.

	V_P [m/s]	V_S [m/s]	ρ[kg/m³]	ϕ [%]	κ[D]
Shale	2187	752	2138	-	-
Sand	-	-	2121	30	1.0

Using equations (1)-(4), the P-wave velocity (V_p), attenuation (1/Q), normal-incidence reflection coefficient (NI) and phase angle (φ) are plotted with respect to frequency and oil saturation/reservoir porosity. Both cases show similar velocity gradients with porosity obviously having a larger difference. The porosity case shows an order of magnitude difference from the oil saturation case in all models except for the attenuation. The attenuation in both cases is around 10^{-3}. A phase shift is visible in the porosity case at around 34% porosity which can also be seen in the NI results (Figure 3c and 4c) and the frequency dependency results (Figure 4b).

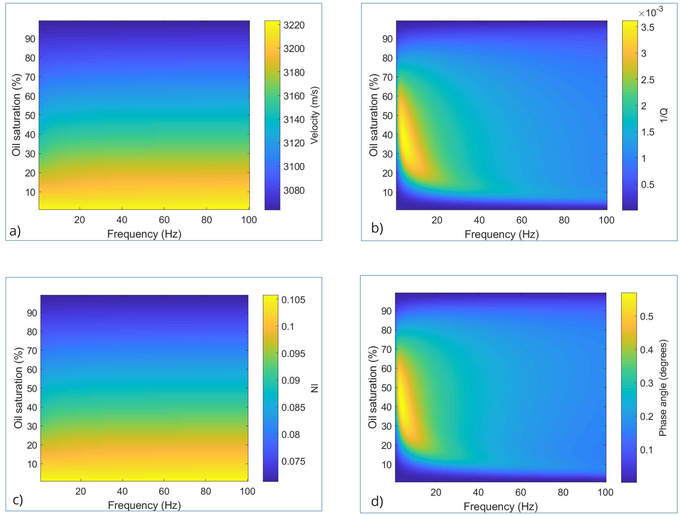


Figure 3: Modeled results with respect to oil saturation and frequency. Porosity is, as in Table 2, fixed at 30%. Warm and cold colors indicate high and low values, respectively.

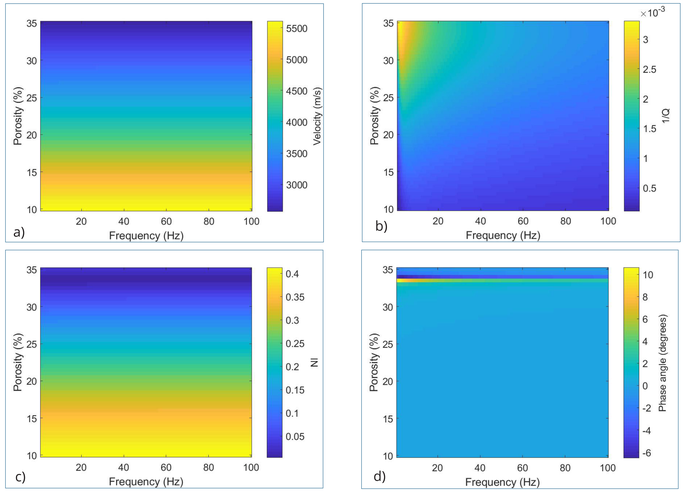


Figure 4: Modeled results with respect to porosity and frequency. Oil saturation is fixed at 63%. Warm and cold colors indicate high and low values, respectively.

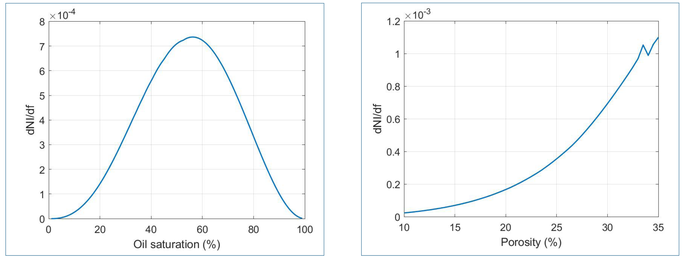


Figure 5: Frequency dependency of NI with respect to (a) oil saturation and (b) porosity.

Conclusion

The porosity affects the reservoir reflectivity, velocity and phase significantly more than the oil saturation does. The attenuation however is more affected by saturation than porosity at Φ≤30%.

White's model relies on the difference in bulk moduli of the two saturating fluids to cause the wave-induced fluid-flow and thus attenuation. Our model of brine and oil saturated reservoir does not cause significant attenuation as the two fluids have similar bulk moduli.

Although the attenuation occurs, it is very minor and thus for a real seismic dataset, would most likely be drowned by noise and/or other types of attenuation. The same applies to the frequency dependency of the normal-incidence reflection coefficient as it is too small to be seen in real world application.

The results indicate that the method is not promising for deeper oil exploration, but it could be beneficial to look at shallow oil reservoirs as the difference in the bulk moduli might be magnified by less overburden.

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