The influence of fluid distribution on seismic amplitude variation

Qiaomu Qi¹, Tobias M. Müller² and Boris Gurevich³.

¹Curtin University, Perth, Australia; ²CSIRO, Perth, Australia. qiaomu.qi1@postgrad.curtin.edu.au

Summary

The amplitude-versus-offset (AVO) analysis is known to be affected by attenuation due to mesoscopic flow in patchy-saturated reservoir. The distribution of the fluid patches controls the significance of this attenuation. In this work, we study the relation between amplitude variation and fluid patch size for Class 3 AVO anomaly. The results show that centimetre to metre-scale fluid patches will substantially change the characteristics of the reflection coefficient. The amplitude decreases with increasing patch size in both frequency and angle domains. For patchy-saturated rocks involving centimetre to metre-scale fluid heterogeneities, interpreting amplitude-versus-angle (AVA) response by Gassmann theory will lead to underestimation of gas saturation.

Introduction

Extracting saturation information from seismic data demands a solid understanding of the relation between elastic properties and pore fluid distribution. When the reservoir rock is partially saturated by two immiscible fluids, the fluid mixture can uniformly distribute in the pore space. In this case, Gassmann theory can be invoked to predict the seismic velocity. On the other end, each fluid phase can occupy many pore spaces and forms as mesoscopic patches. This scenario entails more complicated velocity–saturation relation and is typically linked to time-lapse projects such as CO₂ injection or enhanced oil recovery (Müller et al., 2014). The scale of such fluid patches can differ by orders of magnitude depending on the flow rates and driving forces. Wave-induced pressure diffusion across these mesoscopic fluid patches can give rise to attenuation and change on time-lapse signal. AVO technique is a powerful tool for reservoir monitoring. However, its physical interpretation of the amplitude variation is based on Gassmann theory which implies uniform saturation and non-attenuation. Till recent years, several AVO studies have been done with consideration of attenuation and dispersion in a patchy-saturated reservoir (Liu et al., 2011). The fluid distribution is known to control the attenuation due to mesoscopic flow. However, direct analysis of AVO sensitivity on fluid patch size is still missing. In this work, we explore the relation between amplitude variation and fluid distribution by applying recently developed patchy saturation model.

Methods

To study the seismic reflection between rocks of different properties, we choose a simple two-layer model where a low impedance sand layer is encased between two higher impedance shale layers. This type of reservoir model is categorised as Class 3 AVO anomaly. We assume the reservoir sand is
partially saturated and dispersive whereas the overburden shale is fully saturated and non-dissipative at seismic frequencies.

Though we are dealing with seismic reflection between two porous media, in which case, the mode conversion across the interface will generate Biot slow wave. However, the energy carried away by the latter is negligible at seismic frequencies. Therefore, we can simplify the problem to reflection between two viscoelastic half-spaces which can be solved by the extended Zoeppritz equation for attenuative media (Liu et al., 2011). The resulting reflection coefficient incorporates the frequency-dependent phase velocities and attenuation of the rocks.

We assume the attenuation is negligible for the overburden shale and consequently constant velocity. We model the attenuation of the reservoir sand using recently developed patchy saturation model including capillary effect (Qi et al., 2014). In this model, the fluid patches are assumed to have irregular shapes and distribute in a random fashion, which is the likely case for real rock formations and saturation conditions. In next section we analyse the amplitude variation resulting from P-wave reflection between the cap rock and the patchy-saturated reservoir rock with particular emphasis on the effect of fluid distribution.

Results

The presence of centimetre to metre-scale fluid patches have been reported from synthetic and field studies (Müller et al., 2014) that will have substantial change on seismic signatures due to mechanism of wave-induced pressure diffusion. The characteristic frequency of this mechanism is given by

\[ f_c = \frac{1}{2\pi \eta b^2} \frac{\kappa N}{\kappa/\eta N}, \]

where \( \kappa/\eta N \) is the fluid mobility and parameter \( N \) signifies the fluid sensitivity of the rock. The critical frequency is inversely proportional to the characteristic fluid patch size \( b \). As can be seen from Figure 1 (a), larger fluid patch size results in a shift of acoustic impedance dispersion towards lower frequency. On the other hand, larger patch size gives rise to an elevated impedance-saturation relation (ISR) as shown in Figure 1(b). The dispersion and ISR are bounded by Gassmann-Wood and Gassmann-Hill predictions. Despite the dispersion, the impedance contrast of the two-layer model is
constantly negative suggesting AVO anomaly is Class 3 throughout the frequency and saturation ranges. According to equation 1, for reservoir sand having a characteristic frequency below 100 Hz, the required patch size is 8 centimetres or above. Next, we analyse the sensitivity of amplitude variation on these centimetre to metre -scale fluid patches.

The magnitude of the reflection coefficient for incident P-wave travelling from the upper shale to the lower sand is plotted in Figure 2(a) as a function of frequency. The magnitude is interpreted as the normalised amplitude of the reflected P-wave. For uniform saturation, the amplitude is predicted by Zoeppritz equation in combination with Gassmann-Wood theory. This is the scenario of the largest impedance contrast (see Figure 1(a)), hence resulting in the highest amplitude-versus-frequency (AVF) as indicated by the top black line. While for patchy saturation AVF shows small variation for patch size between 0 and 10 centimetres. AVF decreases gradually with increasing patch size from 10 centimetres to 1 metre. Interestingly the shape of the AVF is qualitatively the same with the flipped impedance dispersion (Figure 1(a)).

![Figure 2. (a) Magnitude of the reflection coefficient plotted as function of frequency. Incident angle is 0 degree. (b) Magnitude of the reflection coefficient plotted as function of angle. Frequency is 50 Hz. In both plots, saturation is 50%. Colorbars denote the characteristic patch size.](image)

Figure 2(b) demonstrates the angle-dependency. The amplitudes increases with increasing angle of incidence as expected from Class 3 AVO anomaly. Strong angle-dependency is observed above 20 degree. Larger fluid patches produce overall lower amplitudes. Figure 2(a) and Figure 2(b) shows that, even at the same degree of saturation the magnitude of the amplitude can depend on the spatial fluid distribution. From uniform fluid mixture to patch size of 1m, the amplitude reveals maximum 20% reduction in both frequency and angle domains.

Whether the reservoir fluids are distributed uniformly or in a patchy manner will have implications on AVO inversion. To illustrate this point, we compare AVA responses at various saturations modelled by Gassmann theory and patchy model. We take a typical seismic frequency of 50 Hz. The patch size is assumed to be weakly dependent on saturation and on the magnitude of 1 metre.

In Figure 3, the AVA responses at the end-member saturations are the same for both models. The gas sand has appreciably stronger reflection than the wet sand. For uniform saturation, AVA responses for 0% to 99% gas saturations are localised near the gas bound. Contrarily in patchy saturation, Avas are evenly distributed between the bounds. The difference can be explained by invoking the impedance-saturation relation (Figure 1(b)). The random patchy saturation model entails a gradual change of the
impedance with saturation which results in smoothed impedance contrast. Whereas the Gassmann-Wood model implies a strong “Gas effect”, this causes a sudden drop of the impedance contrast near full water saturation. The comparison indicates that, in presence of “seismic scale” fluid patches, interpreting AVA with Gassmann model will underestimate the gas saturation.

![AVA signature predicted by Gassmann-Wood theory for various saturations; (b) AVA signature predicted by patchy model with 1m patch size for various saturations. In both plots, frequency is 50 Hz.](image)

**Figure 3.**

**Conclusions**

In this work, we study the seismic reflection between a high impedance shale and partially saturated soft sand. The results show that the spatial distribution of the fluid heterogeneities can significantly change the shape and magnitude of the reflection coefficient. The shape of AVF is determined by the acoustic impedance dispersion. The magnitude of both AVF and AVA decreases with increased patch size from centimetre to metre-scale. By comparison of AVA responses of various saturations modelled by Gassmann theory and patchy model, we conclude that Gassmann theory underestimates gas saturation in patchy-saturated rocks involving centimetre to metre-scale fluid patches. The results may have further implication on applying time-lapse AVO technique for mapping subsurface fluid distribution.

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**References**

