Seismic attenuation in rocks saturated with multi-phase fluids.
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Summary
There is currently a great deal of interest in the question of whether seismic attenuation can be used to make inferences about the saturating fluid. Apparent gas related attenuation anomalies have been reported, but it is unclear how these anomalies can be related to the extent of gas saturation. Many theories have been developed for the case of partial saturation, but a number of questions remain unclear, particularly how the effect of the partial saturation can be combined with the “squirt-flow” mechanism which occurs from single fluid saturation and the effects of different pore-fluid saturation patterns. We develop a new rock physics model which addresses these issues, based on inclusion modeling. The model shows that introducing a small amount of gas into water can lead to an increase in attenuation, but a potentially much more important effect is that of the change in “effective fluid viscosity”, which is important for larger values of percentage gas saturation.

Introduction
An important goal for seismic exploration is the ability to discriminate between different saturating fluids. The AVO technique has proven to be extremely useful for this purpose, but it is known to be weak at differentiating between commercial and non-commercial quantities of gas. When small quantities of gas are introduced into water, the bulk modulus of the mixture falls sharply. This rapid reduction in the effective fluid bulk modulus shows up clearly in the AVO signature, giving rise to a “false” anomaly, and it is extremely difficult to separate such false anomalies from those caused by deposits with greater gas saturation.

Recently, a great deal of research has been carried out into the question of whether attenuation measurements can be used to provide a solution to this problem (Li et al., 2005; Odebeatu et al., 2006). The results of these investigations can be considered to be promising, particularly when the ideas are used in conjunction with modern spectral decomposition techniques, and apparent attenuation anomalies associated with known gas reservoirs have been shown. This raises the question of whether we are able, even in principle, to interpret an observed attenuation anomaly in terms of the degree of gas saturation.

A convincing answer to this question requires studies based both on theoretical and experimental investigations. In this paper we develop a new rock physics model for seismic wave propagation through permeable materials saturated with multi-phase fluids. We show that attenuation is influenced by the fluid bulk modulus, and that, as with AVO, introduction of small amounts of gas into water can give rise to increased seismic attenuation. Nevertheless, for attenuation the fluid viscosity plays a controlling role, and for gas-water mixtures the “effective fluid viscosity” is a strong function of the gas saturation. This suggests that attenuation measurements may indeed in principle be able to give information on gas saturation which is not available through AVO analysis.

Theory
Many authors have studied the effects on seismic wave propagation of the rock being “partially saturated”. By far the most popular approach is that based on the work of White (1975).

White’s model is based around the deformation of a porous rock saturated with one fluid which contains a spherical “bubble” of a second fluid. The model shows that the existence of the bubble has an important effect on the behaviour, and leads to very significant magnitudes of attenuation and dispersion. The attenuation and velocity depend strongly on frequency, the permeability of the rock, the fluid viscosities and the radius of the “bubble”. White’s work is considered to be a strong candidate mechanism for the gas-related attenuation anomalies which have been observed.

Dvorkin et al. (1994) and Taylor and Knight (2003) have provided solutions in the same spirit for the case of “patches” of one fluid within a saturation of a different fluid. The main uncertainty is the effect of the geometry of the distribution of the different fluids. Carcione et al. (2003) carried out numerical wave-propagation modeling and found good agreement between their results and the predictions of the White model.

Gist (1994) analyzed velocities derived from laboratory resonant-bar measurements carried out with varying degrees of water saturation. He showed convincingly that to interpret the results required two separate concepts; the “gas pocket” model based on White’s solution and the “local” or “squirt-flow” mechanism. To that end he made a correction to the original White model, by using measured velocities in place of predicted velocities. While this approach worked well for the interpretation of the velocity measurements, it is not clear to us how to extend this simple technique to analyse the case of attenuation. This is a particularly important point if we are to model the type of wide-band measurements reported by Batzle et al. (2006).
In this paper we derive a model which attempts to address the two gaps in the theoretical development – the difficulty in combining the local flow and patchy models and the inability to consider complex distributions of the two fluids. The analysis is an extension of our earlier work (Chapman et al., 2002), to which it returns in the case of a single fluid.

We use an inclusion model, in which the pore space is considered to consist of spherical pores and circular cracks of small aspect ratio. Within each crack and pore we allow for the presence of two fluids, which for simplicity we will refer to from now on as water and gas. The principle of the modeling is that we assume that all fluids which are present within a given crack or pore is at the same pressure, but that pressure differences can arise between different cracks and pores. During wave propagation fluid is exchanged between the different cracks and pores in response to these pressure differences. For simplicity of presentation, in what follows we will consider the simplified case of a single crack and a single pore, but the case of an arbitrary number of cracks and pores can be solved in the same way.

To begin with, we derive the equation of state for each crack and pore, which relates the mass of each fluid within the inclusion to the geometry of the inclusion, the applied stress and the common fluid pressure. This is given by the equation:

$$\frac{m^g_1}{\rho^0_g} + \frac{m^w_1}{\rho^0_w} = V_1^0 \left( 1 - \frac{\sigma}{S_1} + \frac{p_1}{S_2} + \kappa p_1 + \varepsilon p_1 \right)$$

$$-2\varepsilon \frac{m^g_1}{\rho^0_g} \rho_1,$$

in which $m^g_1$ and $m^w_1$ are respectively the masses of gas and water present in the inclusion, $\rho^0_g$ and $\rho^0_w$ are respectively the unstressed densities of the gas and water, $V_1^0$ is the volume of the inclusion, $\sigma$ is the applied stress field, $p_1$ is the fluid pressure and $S_1$ and $S_2$ are factors derived from the results of Eshelby (1957) which relate to the geometry of the inclusion. The bulk moduli of the two fluids enter through the two terms $\kappa$ and $\varepsilon$, defined through the combinations:

$$\kappa = \frac{1}{\kappa_w} + \frac{1}{\kappa_g};$$

An important difference between equation (1) and the standard results is that the mass of fluid present in the crack is a non-linear function of the applied stress and fluid pressure. The final non-linear term is proportional to $\varepsilon$, the difference between the fluid bulk moduli, and plays an important role in the wave propagation.

Fluid flow between two inclusions, denoted with the subscripts “1” and “2”, is assumed to be governed by the equations:

$$\partial_t m^g_1 = \frac{1}{\gamma_g} (p_2 - p_1);$$

$$\partial_t m^w_1 = \frac{1}{\gamma_w} (p_2 - p_1);$$

In these equations, the parameters $\gamma_g$ and $\gamma_w$ are functions of the permeability, fluid viscosities and the mass concentrations of the two fluids. This leads later to a concept of “effective fluid viscosity”, which is weighted by the relative mass concentrations of the two fluids.

Together, equations (1) and (2) form a non-linear system of differential equations relating the time dependent applied elastic field to the resulting pressures in each crack and pore. If we assume for simplicity that the applied elastic field follows a unit cosine variation with frequency $\omega_0$, $f = \cos \omega_0 t$, then we may solve the system directly, and find solutions for the pressure in each inclusion of the form:

$$p_1 = G \cos \omega_0 t + \frac{K \cos \omega_0 t}{\sqrt{\frac{A}{\omega_0} \sin \omega_0 t + C}}.$$
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Examining the central features of the model, we find that the behaviour with respect to limiting frequencies is intuitive. For very low frequencies, the fluid has time to move to relieve all the pressure gradients, and we find that the pressure is identical in each inclusion. In this case, our model coincides with the well known “effective fluid model”, which uses a combination of mixture theory for the fluid and Gassmann’s relation. At higher frequencies, the fluid does not have time to move, and the pressure is the same as it would be in the isolated inclusion case. Thus, at the broadest level, our results are consistent with the discussion of multi-phase saturation in, for example, Mavko et al., (1998). In neither limiting case is attenuation present.

The model can be used to study the effect on attenuation of different fluid distributions, including the effect of different percentage gas saturations. As gas is introduced into a water saturated rock, there are two effects on the attenuation, one related to the fluid bulk modulus and another due to the viscosity. The drop in effective fluid bulk modulus as we introduce more gas tends to increase attenuation. Nevertheless, the fluid viscosities are both coupled to the relative mass concentrations of the different fluid phases, and so the frequency range over which attenuation occurs changes as we change the gas concentration. This effect can easily dominate the effect of the fluid bulk modulus change. Figure 2 gives an example of P-wave attenuation as a function of gas saturation, for two different values of the “effective fluid viscosity” parameter.

We compare our results with those of White (1975). Although the parameterization, and the basic physical problem we investigate, are different the modeling agrees with White’s work in terms of the viscosity and permeability dependence of attenuation, and the fact that saturation with more than one fluid can lead to a very powerful attenuation mechanism.

Conclusions

We have derived a rock physics model which examines the effect of saturation with multi-phase fluids. The model differs from current models in two fundamental ways. Firstly, the geometry of the fluid distributions which we assume differ from the standard model of a spherical gas “pocket” or “bubble”. Perhaps more importantly, the model combines the effect of multi-phase fluid saturation with the “squirt-flow” mechanism, in the sense that there is a powerful attenuation mechanism due to local flow even in the limiting case when only one fluid is present. It is believed that this feature will be necessary to fully model attenuation mechanisms relevant to laboratory data. The
model demonstrates how attenuation is coupled to both the bulk moduli and viscosities of the saturating fluid. The “effective viscosity” is a strong function of the relative mass concentrations of the two fluids. This effect is not accounted for in the Gassmann theory which underpins AVO analysis and interpretation. We conclude that, at least in principle, attenuation measurements do contain information on fluid saturation which is not available from AVO analysis alone.

References


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Figure 1: The complex relationship between the applied harmonic stress field (blue line) and the induced pore pressure field (red line).

Figure 2: Sample relationships between P-wave attenuation and gas saturation, for two different values of the “effective fluid viscosity” parameter.