

Z-99 P-WAVE ATTENUATION IN RESERVOIR AND NON-RESERVOIR ROCK

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Abstract

Wave-induced variations of pore pressure in partially-saturated rock or in fully-saturated elastically heterogeneous rock result in oscillatory liquid flow. The viscous losses during this flow are responsible for wave attenuation. The same viscous effects determine the changes in the dynamic elastic moduli of the system versus frequency. These changes are necessarily linked to attenuation via the causality condition. The low-frequency compressional modulus of partially-saturated rock is estimated by means of theoretical fluid substitution using the rock's dry-frame modulus and the harmonic average of the moduli of individual fluid components as the effective bulk modulus of the pore fluid. The high-frequency modulus is estimated by assuming that fluid distribution is patchy, i.e., some large-scale patches are fully water saturated while others contain gas. The difference between the low-frequency and high-frequency moduli is translated into the inverse quality factor through the viscoelastic standard linear solid model. The same causality link between the modulus-frequency dispersion and attenuation is used to estimate the latter in fully-saturated rock. The necessary condition for attenuation is elastic heterogeneity in rock. The low-frequency compressional modulus is calculated by theoretically substituting the pore fluid into the spatially averaged rock's dry-frame modulus while the high-frequency modulus is the spatial average of the heterogeneous saturated-rock modulus. The difference between these two estimates may give rise to noticeable P-wave attenuation if elastic heterogeneity in rock is substantial. Examples provide realistic values for the inverse quality factor (5 to 10) in a gas reservoir and in the background non-reservoir sediment (50 to 100).

Introduction and Problem Formulation

Synthetic seismic modeling is an effective approach to interpreting the seismic amplitude in terms of rock properties (lithology, porosity) and conditions (pore fluid and pressure). Usually a real well is selected from an area geologically similar to the prospect under examination. Then porosity, lithology, and/or fluid and pressure in the well are perturbed according to an anticipated scenario away from well control. The corresponding changes in the elastic properties are calculated from rock physics, and synthetic traces are generated and compared to real seismic data. The underlying supposition is that if the seismic response is similar, the properties and conditions in the subsurface that give rise to this response are similar as well. Systematically conducted perturbational forward modeling helps create a catalogue of seismic signatures of lithology, porosity, fluid, and pressure away from well control and, by so doing, sets realistic expectations for hydrocarbon detection and optimizes the selection of seismic attributes in an anticipated depositional setting.

In principal, three interval properties are needed in synthetic seismic generation: the P- and S-wave velocity and bulk density. In some situations, however, e.g., in gas reservoirs, the

attenuation of the seismic energy is substantial and, therefore, also has to be included in synthetic seismic generation. A simple and reliable rock physics model that links attenuation to basic rock properties is needed for this purpose.

A number of mathematically involved attenuation models have been developed to account for various physical mechanisms occurring at different scales (e.g., Dvorkin and Nur, 1993, Pride et al., 2003). The problem of practical implementation of these theories is, of course, not the complexity of mathematical expressions involved but rather the fact that they require inputs that are not readily available (such as permeability) or, most important, are arbitrary (such as the squirt-flow length and the spatial scales of porosity type). Here we offer a more practical P-wave attenuation model that only requires inputs readily available from well log measurements. The model is based on strong assumptions yet it produces attenuation values that appear realistic within a hydrocarbon reservoir as well as in non-reservoir rock.

Attenuation at Partial Saturation

The frequency range of seismic waves in practical application spans four orders of magnitude, from 10^1 (seismic) to 10^4 (sonic logging) Hz. At such frequency, in partially saturated rock, viscoelastic effects and attenuation may arise from the oscillatory liquid cross-flow between fully-liquid-saturated patches and the surrounding rock with partial gas saturation. The length scale of these patches is at least an order of magnitude larger than the pore scale.

The reaction of rock with patchy saturation to loading due to elastic wave propagation depends on the frequency of the wave. If the frequency is low, i.e., the loading is slow, the oscillations of the pore pressure in a fully liquid-saturated patch and partially saturated domains next to it equilibrate. The patch is “relaxed.” Conversely, if the frequency is high, i.e., the loading of the rock is fast, the resulting oscillatory variations of pore pressure cannot equilibrate between the fully-saturated patch and the domain outside. The patch is “unrelaxed.” The response of the unrelaxed patch is not influenced by the presence of gas next to it.

If the patches in partially-saturated rock are relaxed which may occur at very low frequency, it is valid to use the concept of the effective pore fluid that is a mixture of liquid and gas. The effective bulk modulus of this mixture is the harmonic (or isostress) average of the moduli of water and gas. Then the bulk modulus of the partially saturated region is determined by Gassmann's equation where the pore-fluid bulk modulus is that of the mixture.

If the patches in partially-saturated rock are unrelaxed which may occur at high frequency, the concept of the effective pore fluid is not applicable. The bulk modulus of a fully-saturated patch comes from Gassmann's equation where the fluid is water. Analogously, the bulk modulus of a gas-saturated patch comes from Gassmann's equation where the fluid is gas. The effective compressional modulus of the partially saturated rock is the harmonic average of the compressional moduli of the water-saturated and gas-saturated patches. This high-frequency modulus is always larger than that calculated at low frequency.

This modulus difference can be viewed as the modulus-frequency dispersion and linked to attenuation by one of viscoelastic theories. Here we choose the standard linear solid model which offers a simple formula that links the maximum possible inverse quality factor to the compressional modulus limits at high and low frequency.

Attenuation in Wet Rock

The mechanism of attenuation in wet rock in the practical frequency range is similar to the ultrasonic pore-scale squirt flow where wave-induced oscillatory cross-flow develops between the soft and stiff parts of a pore. The difference is in the scale of the flow. If elastic heterogeneity is present in wet rock at the macroscopic scale, such cross-flow develops

between the softer and stiffer parts of the rock. At low frequency, the soft part and stiff part are in hydraulic communication. The low-frequency effective bulk modulus is calculated by conducting Gassmann's fluid substitution into the harmonically averaged (according to the Backus, 1962, average) dry-rock modulus of the rock. At high frequency, fluid substitution is conducted separately for the soft and stiff part and then the resulting wet-rock moduli are harmonically averaged. The high-frequency modulus resulting from this operation is always larger than the low-frequency modulus. This difference is treated as the modulus-frequency dispersion and the standard linear solid model is used to calculate the maximum inverse quality factor. This method is applied to a vertical interval by using running averages.

Examples of Attenuation Calculation in Wells

Consider a Gulf Coast well (Well A) that penetrates an overpressured shale interval with gas sand at the bottom (Figure 1). The impedance in the gas sand is smaller than that in the shale above it. The calculated inverse quality factor is (as expected) large in the gas sand, with the quality factor Q becoming as low as 8, and negligibly small in the shale, except for the upper part where elastic heterogeneity in the shale is present and, as a result, Q is about 80.

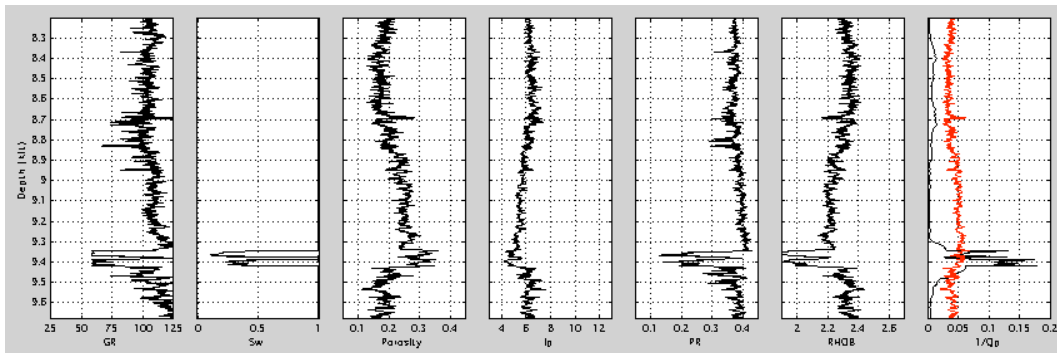


Figure 1. Well log curves in an overpressured Gulf Coast gas Well A. From left to right – gamma-ray; water saturation; total porosity; P-wave impedance; Poisson's ratio; bulk density; and the inverse quality factor. The red curve in the inverse quality factor frame is calculated according to the Koesoemadinata and McMechan (2001) equations.

Let us next calculate the elastic properties in the interval under examination for wet conditions by theoretically replacing the gas in the sand by the formation water using Gassmann's fluid substitution. The resulting impedance in the sand is larger than that in the shale above it (Figure 2). This impedance difference constitutes discernable elastic heterogeneity in the interval. The result of this elastic heterogeneity is attenuation that stands out of the background with Q reaching as low as 20.

Consider now a gas wells with fairly consolidated sand and shale intervals. The porosity in the upper sand in Well B is about 0.3 while that in the lower sand is about 0.25 and the lower sand is much stiffer than the upper sand (Figure 3). The calculated quality factor appears to strongly depend on the stiffness of the gas reservoir. It is about 7 in the upper, relatively soft sand, and about 20 in the lower, relatively stiff sand.

Discussion and Conclusion

The two critical questions are (1) whether the model offered here produces realistic results and (2) how these results compare to those offered by other practical models. First, the Q values shown in Figures 1 to 3 are very similar to those measured in the field in gas sand (Klimentos, 1995) which is in the 5 to 10 range as well as in non-reservoir rock (on the order of 100). Second, the only practical alternative to the model offered here, the empirical relations due to Koesoemadinata and McMechan (2001), do not offer the observed Q

discrimination between reservoir and non-reservoir rock (the red curves in the figures). Also, this empirical model produces attenuation values in non-reservoir rock larger than realistically possible (the seismic signal may essentially disappear due to attenuation if such low Q values are indeed present everywhere in the subsurface).

The strong points of our theory are that it (1) is based on first principles; (2) allows for calculating Q from basic inputs that are readily available from borehole measurements; and, most important, (3) produces Q values that are consistent with field measurements. Therefore, we feel that the theory of P-wave attenuation put forth in this paper is theoretically and practically viable and can and should be used for realistic attenuation calculations in reservoir and non-reservoir rock.

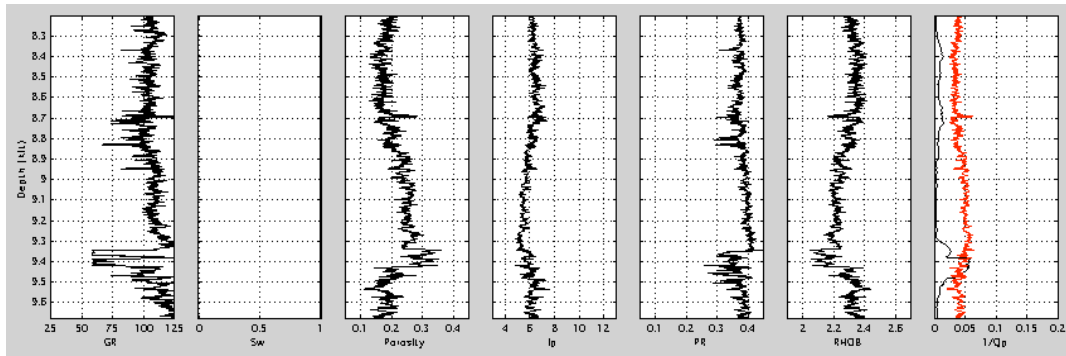


Figure 2. Same as Figure 1 but for the wet interval where the elastic properties are calculated from the original well log data via fluid substitution.

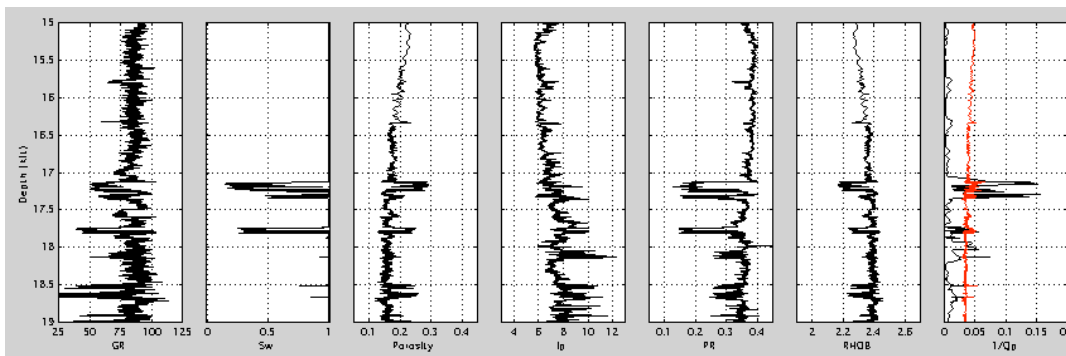


Figure 3. Same as Figure 8 but for Well B.

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