Modeling attenuation in reservoir and nonreservoir rock

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Elastic waves attenuate in earth. The number of wavelengths over which the amplitude decreases by a factor of ten is $0.733 \cdot Q$, where Q is the quality factor. For $V_P = 3$ km/s and frequency $f = 30$ Hz, the wavelength $\lambda = V_P/f = 0.1$ km. Then for $Q = 10$, the amplitude decreases by a factor of 10 as the wave travels $0.733 \cdot Q \cdot \lambda = 0.733$ km.

Such an effect should be accounted for in synthetic seismic modeling at a well. This practical incentive for estimating Q from standard well data is complemented by a more fundamental quest to relate it to rock properties and conditions and their spatial and temporal heterogeneity. The ultimate aspiration is to add attenuation to the arsenal of physics-driven seismic attributes, such as the impedance and V_P/V_S ratio, used for delineating and characterizing reservoirs and monitoring production.

Yet, in spite of decades of experimentation and theorizing, we are much farther from inferring porosity, lithology, and fluid from attenuation than from velocity or impedance. Among the reasons are: (1) scarcity of relevant and consistent field data and (2) phenomenological complexity and, often, inconsistency of available data, which makes generalization difficult.

Attenuation theories use a fundamental empirical fact: Elastic waves do not attenuate in very dry rock. Thus the amplitude loss is usually linked to the energy loss in the oscillatory pore-fluid flow triggered by the passing wave. The viscous-flow friction irreversibly transfers part of the energy into heat. This flow may be especially strong in partially saturated rock where the viscous fluid phase (water) moves in and out of the gas-saturated pore space.

Such viscous-friction losses may also occur in fully saturated rock where elastic heterogeneity is present. Deformation due to a stress wave is relatively strong in the softer portion of the rock and weak in the stiffer portion. The resulting unevenness forces the fluid to flow between the softer and stiffer portions. Such cross-flow may occur at all spatial scales.

Microscopic "squirt-flow" develops at the submillimeter scale because the pore space includes compliant cracks as well as stiffer equidimensional shapes. Macroscopic "squirt-flow," which is relevant to the field seismic experiment, occurs due to the large-scale elastic heterogeneity in the rock frame. This mechanism has recently received a rigorous mathematical treatment by Pride et al. (2003) in a "double-porosity" model.

Practical application of these theories is hindered by their reliance, by necessity, on variables that are not readily available (permeability) or simply not measurable (the squirt-flow radius or scale of macroscopic elastic heterogeneity). Therefore, simple practical rules for estimating Q are desirable.

Observations. Consistent and accurate field measurements of Q are rare due to practical difficulties of extracting attenuation from reflection seismic data, crosswell, VSP, and full waveform borehole data.

Q values estimated from seismic events are usually very high. In-situ Q in marine sediments has been estimated to be ~30 in wet sand and as high as 100 and even 400 in silt and clay. Kvamme and Havskov (1988) estimate Q about 950 at 10 Hz while in Lilwall (1988), Q is between 100 and 200 in the upper 3 km of the crust. VSP data have been used to calculate Q exceeding 300 in basement rock at depths below 1.8 km. Crosswell tomography has been used to estimate attenuation in the 200-2000 Hz frequency range. Q is between 30 and 50 in soft (V_P between 2.6 and 3.0 km/s) sand/shale sequence and reaches 100 in chalk and limestone. A Q of 33 has been estimated from a high-resolution 2D seismic data over a Florida carbonate high-porosity aquifer system where V_P is between 2 and 3 km/s and density is about 2 g/cc.

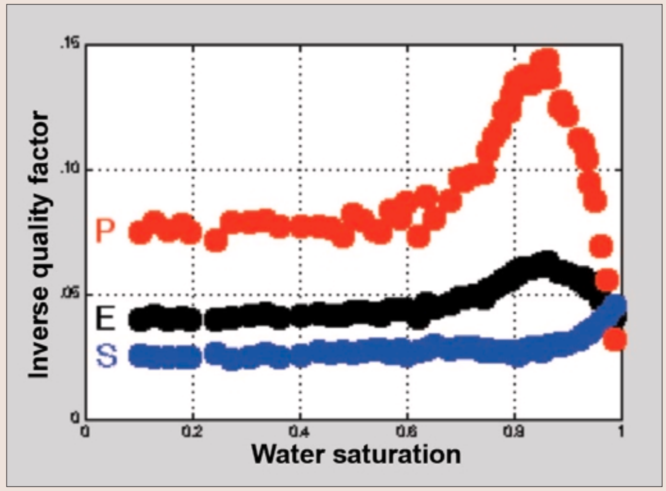

Figure 1. *The inverse quality factor in Massillon sandstone versus water saturation (after Murphy, 1982). Frequency range is 300-600 Hz. The E- and S-wave data (black and blue, respectively) are measured while the P-wave inverse quality factor (red) is calculated from these data.*

A study by Klimentos (1995) is one of the few relevant to hydrocarbon exploration. It reports, based on sonic waveform analysis, that Q falls between 5 and 10 in gas sandstone of about 12% porosity (Q^{-1} between 0.1 and 0.2) while it may easily exceed 100 (Q^{-1}<0.01) in oil- and water-saturated intervals. Attenuation is large in rock with partial gas saturation and small in liquid-fill rock.

The attenuation values obtained in the lab are usually larger than those measured in the field. Still, they confirm the fact that large attenuation manifests rock with partial gas saturation. It has been shown that attenuation peaks at small gas saturation (Figure 1), an observation potentially useful for discriminating reservoirs with residual gas from commercial-gas reservoirs.

Model. To quantify Q we use the physical principle that links attenuation to the changes in the elastic modulus versus frequency. A simple illustration of this link is for an ideal viscoelastic system, the standard linear solid:

$$2Q_{Max}^{-1} = \left(M_H - M_L\right) / \sqrt{M_H M_L},$$

where Q_{Max}^{-1} is the maximum inverse quality factor; M_H is the compressional modulus at very high frequency; and M_L is the compressional modulus at very low frequency. The compressional modulus is the product of the bulk density and P-wave velocity squared. This equation provides the upper bound for attenuation without addressing its frequency dependence. By using it we reduce the problem to finding M_L and M_H.

The frequency range of seismic waves in practical applications spans four orders of magnitude, from 10^1 (seismic) to 10^4 (sonic logging) Hz. The pore-scale Biot and squirt flow attenuation mechanisms are not likely to be engaged at these frequencies. Rather, in partially saturated rock, viscoelastic effects and attenuation 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.

To recognize physical reasons for the existence of patchy saturation, consider a relatively large volume of rock that includes several smaller sand volumes whose clay content and/or grain size vary. Such variations usually dramatically affect permeability and, simultaneously, capillary pressure curves and irreducible water saturation (S_{Wirr}). In a state of capillary equilibrium, capillary pressure is the same for adjacent patches whose S_{Wirr} is different. As a result, some patches (with larger S_{Wirr}) may be fully water-saturated while other patches (with smaller S_{Wirr}) may contain gas. The whole volume will have patchy distribution.

The reaction of rock with patchy saturation to loading by the elastic wave depends on the frequency. If it is low and 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 and the loading is fast, the resulting oscillatory variations of pore pressure cannot equilibrate between the fully saturated patch and the domain outside. The patch is "unrelaxed."

Therefore, to estimate the low-frequency modulus M_L, we assume that the fluid in a volume of rock is in perfect hydraulic communication and its effective bulk modulus K_F is the harmonic average of those of water K_W and gas K_G: $K_F^{-1} = S_W K_W^{-1} + (1-S_W)K_G^{-1}$, where S_W is water saturation. Next, Gassmann's equation with K_F is used to calculate the bulk modulus of the rock. M_L is the bulk modulus plus 4/3 of the shear modulus.

To estimate the high-frequency modulus M_H we assume that all liquid in partially saturated rock is concentrated in fully saturated patches and the rest of the rock is filled with gas. Then, the volumetric concentration of the fully saturated patches in the system is S_W. If we assume in addition that the shear modulus is the same for the liquid-saturated and gas-saturated patches, the effective compressional modulus of the partially saturated rock is the harmonic average of the compressional moduli of the wet rock M_{WET} and rock with only gas M_{DRY}: $M_H^{-1} = S_W M_{WET}^{-1} + (1-S_W M_{DRY}^{-1})$. M_{WET} and M_{DRY} can be found from Gassmann's equation if the properties of the dry frame and pore-fluid components as well as porosity are known. In practice, in the well where V_S is not available or reliable, we can use the V_P-only fluid substitution of

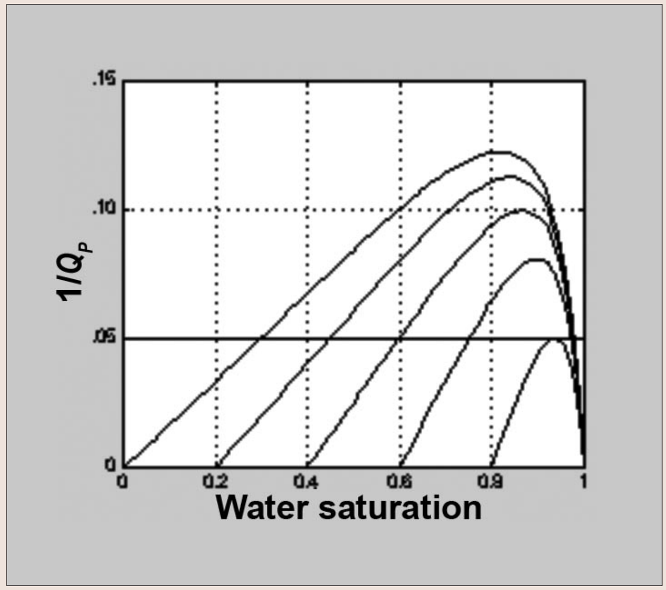

Figure 2. Theoretical P-wave inverse quality factor versus water saturation for a hypothetical clean sandstone sample with porosity 0.3. The only variable is the irreducible water saturation. It increases from 0 to 0.8 with step 0.2. Each curve corresponds to a fixed irreducible water saturation.

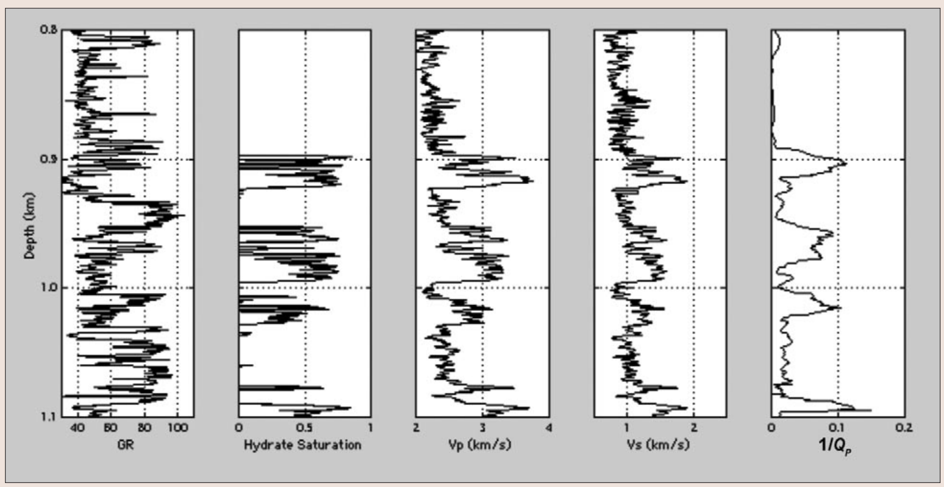

Figure 3. A gas hydrate Arctic well. From left to right: GR, methane hydrate saturation in the pore space, P- and S-wave velocity, and the modeled inverse quality factor.

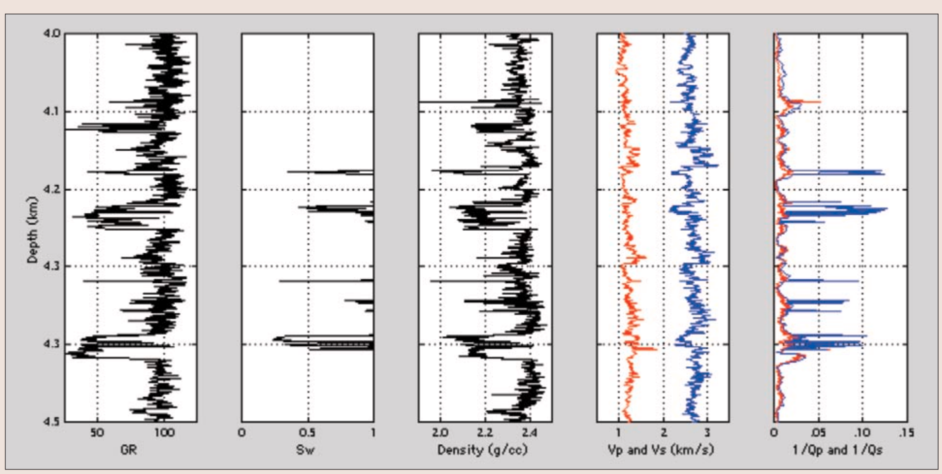

Figure 4. A gas well in GoM. From left to right: GR, water saturation, bulk density, P- and S-wave velocity, and the modeled inverse quality factor (blue for P and red for S).

Mavko et al. (1995) instead of Gassmann's equation.

An important parameter accounted for in our model is the irreducible water saturation. High S_{Wirr} is usually due to strong capillary forces which in turn are due to small grain size and poor sorting. Strong capillary forces limit the mobility of the pore fluid, thus reducing the intensity of the wave-induced oscillatory flow and, respectively, reducing the viscous losses and attenuation.

The modeled P-wave inverse quality factor Q_P^{-1} in partially saturated sand is plotted versus S_W and for varying S_{Wirr} in Figure 2. Notice that the sample with $S_{Wirr} = 0.6$ (shaley sand) has the same theoretical Q_P^{-1} at $S_W = 0.70$ as the sample $S_{Wirr} = 0.2$ with (clean sand) at $S_W = 0.45$. This means that attenuation can serve as a quantitative saturation discriminator only among similar lithologies whose S_{Wirr} is approximately the same.

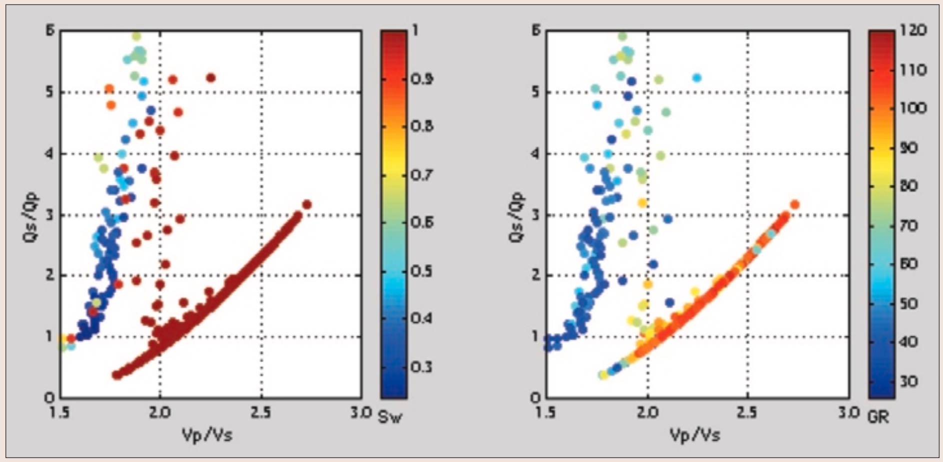

Figure 5. The quality factor ratio versus velocity ratio color-coded by saturation (left) and GR (right) for the example shown in Figure 4.

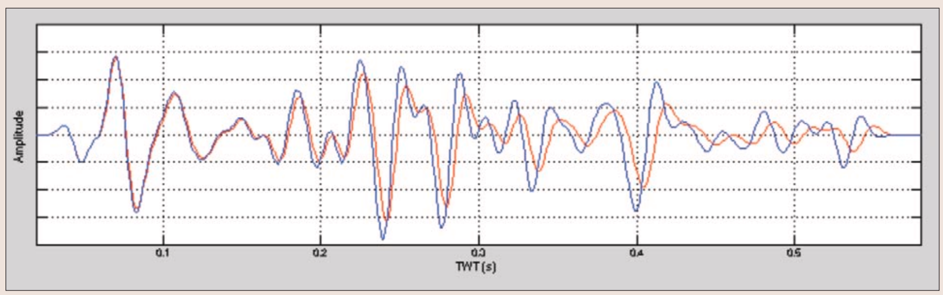

Figure 6. Normal-incidence 30-Hz synthetic traces with attenuation (red) and without attenuation (blue) for the example shown in Figure 4. The traveltime is counted from the top of the interval.

Attenuation in a reservoir is superimposed upon background attenuation in nonreservoir sediment with $S_W = 1.0$. To model this background we use the same causality link between the modulus-frequency dispersion and attenuation as in partially 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 saturated-rock modulus. The difference between these two estimates may give rise to noticeable P-wave attenuation if elastic heterogeneity in rock is substantial. Dvorkin and Uden (2004) show that this is the case ($Q_P^{-1} \approx 0.1$) in sediment with methane hydrate where V_P may rapidly vary from less than 2.5 km/s in the shale background to almost 3.5 km/s in the sand with high hydrate content (Figure 3).

The S-wave attenuation model rests on laboratory and field evidence that Q_S: (1) weakly depends on water saturation and (2) approximately equals Q_P at 100% water saturation. Our theory assumes that: (1) Q_S is related to the shear-modulus-versus-frequency dispersion by the same viscoelastic model as Q_P (e.g., the standard linear solid) and (2) the shear-modulus-versus-frequency dispersion is linked to the compressional-modulus-versus-frequency dispersion.

To model this link, we assume that the reduction in the compressional modulus of wet rock between high frequency and low frequency is due to the introduction of a hypothetical set of defects (e.g., cracks). Next, we assume that the same set of defects is responsible for the reduction in the shear modulus between high frequency and low frequency. Then, by using (e.g.) Hudson's theory for cracked solid, we link the shear modulus versus frequency dispersion to that of the compressional modulus with the proportionality coefficient being a function of the V_P/V_S ratio. As a result,

$$\frac{Q_S}{Q_P} = \frac{5}{4}\frac{(\gamma-2)^2}{(\gamma-1)} / \left(\frac{2\gamma}{3\gamma-2} + \frac{\gamma}{3\gamma-3}\right), \quad \gamma \equiv \frac{V_P^2}{V_S^2}$$

The Q_S/Q_P ratio is about 1 for $V_P/V_S = 1.9$ or Poisson's ratio 0.3 which is typical for rock with water. The theory mimic the observation that in wet rock $Q_S \approx Q_P$.

Example. We calculate Q_P and Q_S in a gas well located in the Gulf of Mexico (Figure 4). The background attenuation in wet shale and sand is small. Large Q_P^{-1} manifests gas-saturated intervals while Q_S^{-1} remains small there. The attenuation values modeled at a well ($Q_P \approx 10$ in the gas reservoir and $Q_P > 50$ in shale and wet sand) match the values reported in the literature. The Q_S/Q_P ratio is plotted versus V_P/V_S in Figure 5. A combination of these two attributes (small V_P/V_S and large Q_S/Q_P) helps discriminate gas sand from wet sand and shale.

The normal-incidence synthetic seismic traces computed at the well indicate that the modeled attenuation values do affect the amplitude (Figure 6) and, therefore, Q has to be taken into account in synthetic modeling. This result also means that, in principle, attenuation can be extracted from seismic data and used in reservoir characterization.

Conclusions. A simple physics-driven model presented here allows for estimating attenuation at a well from basic well-log curves. The P- and S-wave quality factor values are realistic and can be used in synthetic seismic modeling as well as in assessing the utility of employing attenuation-related attributes in lithology and fluid prediction.

Suggested reading. "Squirt flow in fully-saturated rocks" by Dvorkin et al. (GEOPHYSICS, 1995). "Rock physics of gas hydrate reservoir" by Dvorkin et al. (*TLE*, 2003). "Permeability dependence of seismic amplitudes" by Pride et al. (*TLE*, 2003). "Seismic wave attenuation in a methane hydrate reservoir" by Dvorkin and Uden (*TLE*, 2004). "Attenuation of P- and S-waves as a method of distinguishing gas and condensate from oil and water" by Klimentos (Geophysics, 1995). "Q in southern Norway" by Kvamme and Havskov (*Bulletin of Seismological Society of America*, 1989). "Regional mb:Ms, Lg=Pg amplitude ratios and Lg spectral ratios as criteria for distinguishing between earthquakes and explosions: A theoretical study" by Lilwall (*Geophysical Journal*, 1988). "Effects of microstructure and pore fluids on the acoustic properties of granular sedimentary materials" by Murphy (Ph.D. thesis, Stanford University, 1982). TLE

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