Some Lapses of Time-Lapse Feasibility and Interpretation Studies

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Abstract

There are numerous successful applications of seismic monitoring of hydrocarbon production in different types of reservoirs. Even quantitative evaluations of saturation and pressure evolution due to reservoir production can be observed in some case histories. Every 4D study, however, involves some restrictive assumptions related to rock and fluid behavior. This paper discusses some shortcomings of time-lapse feasibility and interpretation studies as well as yields an insight on the possible errors involved.

Introduction

4D or time-lapse seismic technology became a commonplace in the development of oil fields. It has already been showing excellent results in Brazil, even with the severe repeatability issues due to weather, tide and marine current conditions. Among the best examples can be highlighted the cases of Marlim, Marlim Sul and Marimbá fields. The interpretation of 4D seismic data, adequately supported by rock physics simulations, allows the identification of undrained areas, pressure and flow barriers, development of gas caps, and unexpected water influxed zones, among many other effects that could not be seen with the flow simulation results and production data alone.

In many case histories of time-lapse seismic, the authors had pushed the technology near its limits, allowing the discrimination of pressure and saturation effects or even inverting the 4D seismic volumes directly to pressure and saturation volumes, building the so-called “quantitative 4D seismic” (Lumley et al, 2003; Landrø and Stammeijerz, 2004; MacBeth et al, 2006).

Despite striking successful cases, 4D technical feasibility and interpretation studies are based on some assumptions and approximations whose effects and implications are usually neglected. Our goal with this paper is to point out and discuss some of these aspects, particularly under the point of view of the rock seismic properties.

To avoid too much generality, the attention is focused on important specific issues of saturation and pressure effects on the reservoir seismic behavior and its caveats. The main possible causes of errors will be discussed and the uncertainties will be illustrated with actual examples from Brazil and from literature.

It is worth noticing that the objective here is not to argue about the validity of applying the traditional methodologies on 4D feasibility and interpretation. However, it is important to have some insight on what and how much can be missed with the conventional approaches. Thus, far from providing definitive explanations on these aspects, this work emphasizes the recommendation and the urgency to study them more deeply through the quantification of errors that can be introduced regarding these problems.

Geomechanics

Three main problems related to geomechanical boundary conditions are discussed here: (1) *in situ* stress anisotropy, (2) asymmetry in the reservoir seismic response to stress variation as a result of pore pressure changes and (3) the misuse of effective stress concept.

In situ stress conditions

In 4D feasibility studies and interpretation stages the influence of pore pressure on the reservoir seismic properties are usually supported by laboratory data acquired under isotropic (or hydrostatic) stresses. Nevertheless, rocks in subsurface are generally subjected to anisotropic stresses oriented along three main stress directions, mutually perpendicular and with different magnitudes. In other words, one generally assumes that the stress tensor σ_{ij} can be replaced by a scalar quantity, the overburden pressure P_C. It can, eventually, but not always, be valid.

One model commonly used for the *in situ* stresses is the uniaxial deformation assumption. On the principal coordinate system, there is no shear stress so that the notation should be simplified by using σ_z for the vertical (overburden) stress, σ_x and σ_y for the horizontal stresses. For isotropic, uniform and elastic rocks, the stress state would be such that:

$$\sigma_x = \sigma_y = \frac{\nu}{1-\nu}\sigma_z \tag{1}$$

where ν is the Poisson’s ratio.

The quantity $\nu/(1-\nu)$ is known as lateral stress coefficient, and it will be noted as k in this work. For instance, if ν is about 0.3 (very ordinary for shales), the horizontal stress is only 43% of the vertical stress, far from the litostatic assumption. For Brazilian oil sands it is common ν=0.2 whereas for Gulf of Mexico gas sands ν=0.1, yielding $k = (\sigma_h / \sigma_V)$ as low as 0.25 and 0.11, respectively, very different from the hydrostatic assumption.

There is little knowledge about the impact of the use of hydrostatic instead of anisotropic stress fields on seismic velocity estimation. It is assumed that the average stress governs the seismic velocity response however it is well known that anisotropic stress states induce velocity anisotropy on rocks (Nur and Simmons, 1969). Some laboratory studies under bi-axial stress states indicate that the axial velocity is governed by the mean stress.

Figure 1 illustrates one laboratory example, for the compressional-wave velocities along the axial direction of a cylindrical sandstone sample as a function of the average stress, for various deviatoric stress values (axial stress minus radial stress). This result leans toward those obtained by Shafer *et al*. (2008). So, as an example, if one considers a reservoir under the vertical stress of 8000 psi (55.2 MPa), the mean stress would be only 4000 psi (27.6 MPa), considering *k*=0.25. The velocity difference between isotropic and anisotropic assumption, in this particular example, is around 4%, but the error on velocity, impedance and its variations will depend strongly on the type of rock and burial depth. It is well known that loose sands are generally much more affected by stress changes than consolidated sandstones.

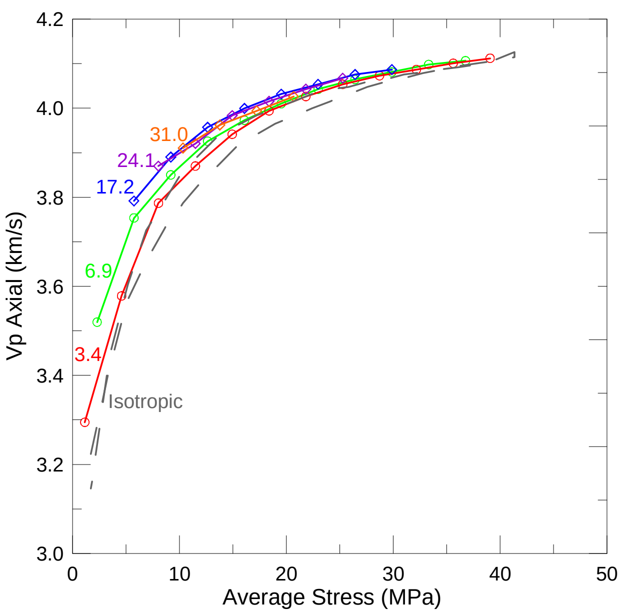

Figure 1 – *Compressional-wave velocities measured on a cylindrical sandstone sample subjected to different bi-axial stress conditions. The deviatoric stress (axial minus radial stress) is indicated by numbers (MPa) near each curve.*

Stress history

Besides the problem of anisotropy of *in situ* stresses, the minimum horizontal stress acting on a reservoir decreases significantly with the decrease of pore pressure, a phenomenon described as stress-depletion response (Addis, 1997). By monitoring the *in situ* stresses on several fields it was observed minimum horizontal stress changes ranging from 0.4 to 1.18 times the pore pressure variation.

Due to the non-linear behavior of the grain boundary stiffness with compressive stress, the seismic response to variations in the reservoir pressure is not symmetric; the response for an increase in pore pressure differs from that one for depletion. It also does not behave as the hydrostatic stress case. For instance, tiny cement in grain boundaries can be broken as the pore pressure is relieved under a triaxial stress condition. Sayers (2007) pointed out that the velocity change depends on the ratio between the variations of horizontal and vertical stress, $k_h = \Delta\sigma_h / \Delta\sigma_V$ and $k_H = \Delta\sigma_H / \Delta\sigma_V$, which are functions of reservoir properties and geometry, as well as the surrounding formations. In the simplest case of an infinite horizontal, linearly elastic layer, this ratio is given by:

$$k_h = k_H = \frac{\nu}{1-\nu} \qquad (2)$$

In 4D studies usually a ratio of $k_h = k_H = 1$ is considered. Figure 2 (modified from Sayers, 2007) illustrates the errors that could be introduced by the assumption of isotropic stress variation, which could be about 13% in this case.

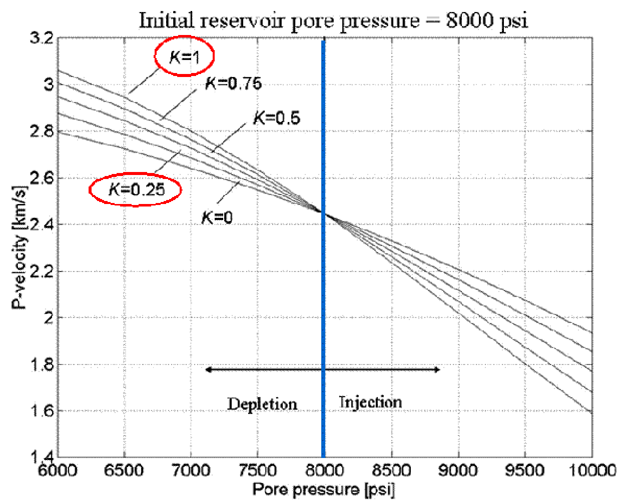

Figure 2 – *Curves corresponding to the compressional velocity of a sandstone sample under the initial pore pressure condition equal to 8000psi, for different values of the parameter k_h. The error introduced by considering isotropic variations (k_h=1) for possible Brazilian reservoir can be as large as 13% (Modified from Sayers, 2007).*

Previous study on the Marlim Field (Formento *et al*, 2007) observed an unexpected small pore pressure influence on the 4D results. A forced regression to lab data were used to mimic the *in situ* rock relaxation (Vernik and Hamman, 2009), and succeeded to explain the obtained effects. On the other hand, these effects could also be explained considering the anisotropic in situ stress and the asymmetric reservoir response to stress changes. The misuse of the effective stress concept could also explain part of this deviation, as detailed below.

Effective stress

Another topic related to the reservoir geomechanics that is addressed here is the effective stress concept. Pore pressure variations are usually inferred with the aid of the effective stress, assumed to be equal to the differential stress,

$$\sigma^e_{ij} = \sigma^d_{ij} \equiv \sigma^C_{ij} - \delta_{ij} P_P \qquad (3)$$

where δ_{ij} is the Kronecker delta function ($\delta_{ij} = 1$ if $i = j$ and $\delta_{ij} = 0$ if $i \neq j$), σ^e_{ij} represents the effective stress tensor, σ^d_{ij} is the differential stress, that is, the difference between the confining stress σ^C_{ij} and the pore pressure, $\delta_{ij} P_P$, which has only non-shear components. Consider the simple litostatic condition, in which the stress components can be replaced by a scalar,

$$P_e = P_d \equiv P_C - P_P \qquad (4)$$

where P_e is the effective stress, P_d the differential stress, P_C the geostatic or overburden stress and P_P the pore pressure. Thus, assuming a 4D invariant overburden, the variation of fluid pressure can be translated into changes in acoustic impedance with the aid of a chart or "abacus" as in Figure 3, for example. In spite of that, theoretical and experimental studies have shown that the effective stress, given by the difference

$$P_e = P_C - n P_P \qquad (5)$$

where n is the effective stress coefficient or pore pressure coefficient, differs from the differential stress (that is, in general, $n \neq 1$).

For a bulk compression, the coefficient n coincides with the Biot-Willis coefficient (Biot and Willis, 1957), as presented by Nur and Byerlee (1971). On the other hand, Berryman (1992) show that, for each rock property, there is a particular effective stress, with a different n coefficient. In the case of seismic velocities, such coefficient would be close to 1 rocks composed of monomineralic and linearly elastic grains (Gurevich, 2006), although in practice, for real rocks, it deviates from the unit and does not coincide with the Biot-Willis coefficient (Vasquez *et al*., 2009).

The hypothesis that the effective stress coefficient is n=1 can lead to errors in the feasibility study phase as well as on the interpretation of reservoir pressure variations in the 4D seismic. For instance, if n = 0.8 the change in the differential stress is 25% larger than the variation of effective stress. Then, for an observed change in the pore pressure, the variations predicted for the acoustic impedance would be overestimated. Furthermore, an observed change in seismic velocity or impedance values, would lead to modifications in the pore pressure underestimated. Xu and colleagues (2006) conclude that such errors in the estimation of pressure effects could be as large as 250% on the estimation of bulk modulus for Lions Sandstone.

Saturation

Homogeneous x heterogeneous fluid distribution

The effects of changes in fluid saturation during the production history of a field are modeled and interpreted using the fluid substitution technique, based on Gassmann's (1951) equations, which require knowledge of some seismic properties of the rock frame, solid and fluid constituents.

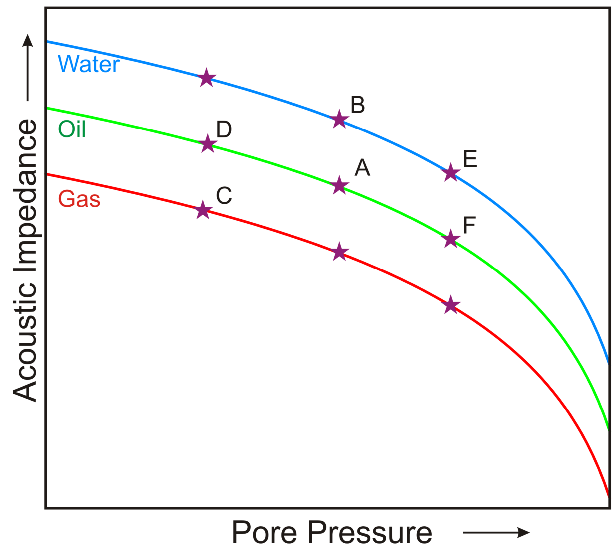

***Figure 3** – Example of possible pressure and saturation scenarios for the acoustic impedance of a producing reservoir. **A** correspond to the original reservoir condition with oil (plus irreducible water) at some given pressure and **B** to the water saturation (plus residual oil) with no pressure variation. On the other hand, **E** represent the situation where there is pressure increase, like on the neighborhood of a water injector well. On the **D** and **F** scenarios exhibit no saturation changes; although, on the first there is pressure decrease and on the second there is pore pressure increase. **C** correspond to gas saturation and pore pressure decrease, that may be common in cases were the production causes a drop in pressure to values below the bubble point and consequent gas cap development.*

The seismic properties estimation of a mixture of fluids are relatively simple. The density is calculated through the mass balance:

$$\rho_F = S_O \rho_O + S_W \rho_W + S_G \rho_G \qquad (6)$$

where ρ is the density, S the saturation and the sub-scripts O, W and G refer to the fractions of oil, water (brine) and gas respectively, normalized to 1 (ie, $S_O + S_W + S_G = 1$), and F relates to the fluid mixture.

The incompressibility K_F of a homogeneous fluid mixture follows Wood's relation:

$$\frac{1}{K_F} = \frac{S_O}{K_O} + \frac{S_W}{K_W} + \frac{S_G}{K_G} \qquad (7)$$

that is, the Reuss average for multicomponent mixtures, taking into account that the stress is equally distributed among each phase (isostress mixture).

In some cases where the heterogeneities in the saturation distribution are relevant and there is enough time to the wave-induced pore pressure equilibrate among the different phases, the Wood's relation cannot be applied to estimate the compressibility of fluid mixtures. The magnitude of these heterogeneities for which the uniform pore pressure assumptions break down are dependent of the frequency of the traveling wave, the permeability of the rock, and the fluid compressibility and viscosity. This situation is usually referred to as patchy saturation.

It can be noticed that, even for this patchy fluid distributions, one can use the rock behavior approximation according to the Gassmann's equation, but using a fluid incompressibility that is greater than the one calculated by the Wood's equation. The upper limit or maximum value of this effective fluid modulus in the patchy saturation is given simply by:

$$K_F = S_O K_O + S_W K_W + S_G K_G \qquad (8)$$

Notwithstanding the above mentioned, the actual effective fluid modulus value will be somewhere between the values given by equations (7) and (8), which coincides with the Reuss and Voigt bounds from the theory of elasticity of composite media. In other words, it represents the minimum and maximum physically possible values for the bulk modulus of a three component mixture, as the deformation or stress is equally distributed throughout the different phases.

In this sense, for time-lapse feasibility and interpretation studies, only the lower and upper bounds for the fluid bulk modulus are rigorously known. Therefore, exercises applying equations (7) and (8) help to decide which one is more adequate (if any).

Studying the effect of mud filtrate invasion on sonic logs acquired over gas saturated formations, Brie *et al*. (1995) observed apparent velocity dispersion caused by the heterogeneous fluid distribution on the fluxed zone. They proposed a scheme to estimate the effective fluid modulus by introducing an extra parameter, e. In this case, it was considered S_{XO} as the fluxed zone water saturation, K_W and K_G as the mud filtrate and gas bulk moduli, respectively. The effective bulk modulus of the fluid in the washed zone, K_F , can be expressed by:

$$K_F = (K_W - K_G) S_{XO}^{e} + K_G \qquad (9)$$

in which the parameter e varies from 1, exhibiting values similar to those estimated by (8), to very high values, approaching the Wood's equation.

Brie claims that, for e = 40, equation (9) is approximately equal to the Wood's relation, but in fact this is only valid for those cases where the gas bulk modulus is much smaller than the one of the mud filtrate. This assumption may fail for usual pressure and temperature condition in the case of heavy gases or condensates at high depths.

To illustrate this failure on the Brie model, Figure 4 shows the estimates for different parameters along the Reuss and Voigt bounds (equations (7) and (8), respectively) in blue, for two water-gas mixtures. In these mixtures the water (or mud filtrate) bulk modulus was assumed to be K_W = 2.5 GPa and for the gas bulk modulus the values K_G=0.01 and 0:20 GPa were used in (a) and (b). It can be seen that the curves calculated with the Brie's relation may be lower than those of the Wood's equation calculations, which is physically impossible. For the gas with K_G = 0.20 GPa this limit is violated even for small values of the e parameter.

Given this failure of the Brie's model, it is better to use a weighted average of equations (7) and (8) to estimate the effective fluid bulk modulus of a patchy mixture.

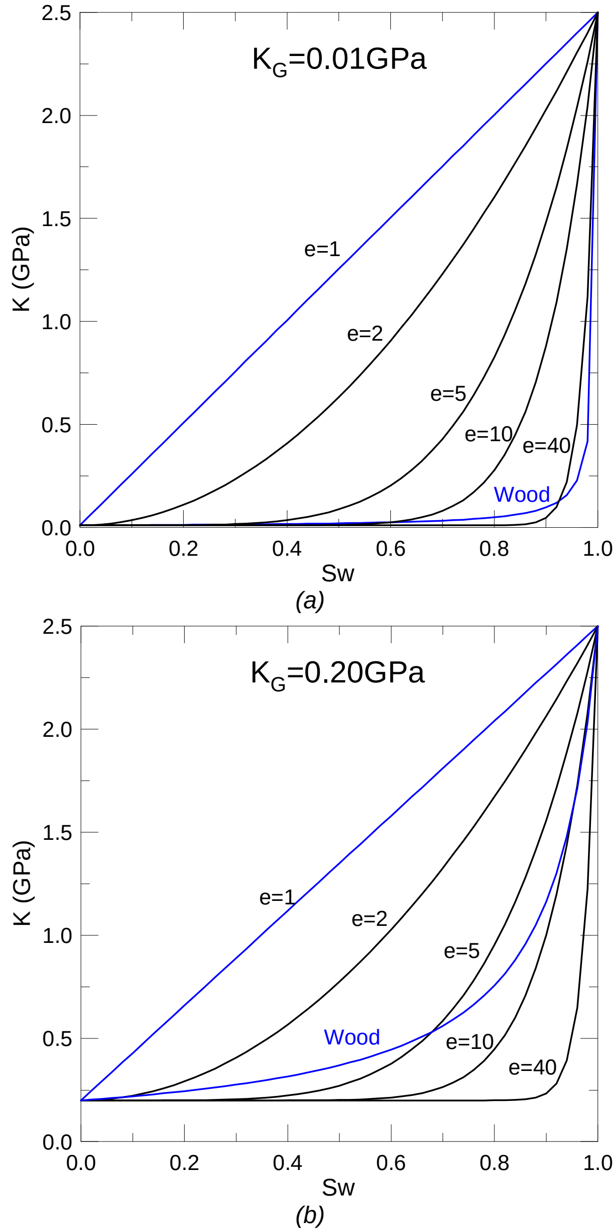

Figure 4 – *Brie's model prediction for the bulk modulus of two water-gas mixtures. The blue lines corresponds to the upper and lower bounds for a two-phase mixture. The Brie's model gives modulus that violates the theoretical bounds.*

Heterogeneous saturation may lead to differences in wave velocities in the order of 5 to 10%, or more, depending on the rock and the fluids involved.

Viscous oils and velocity "dispersion"

The Gassmann's equation is valid, in principle, to estimate the velocities of waves that travel through rocks at seismic frequencies (ideally zero frequency). Biot developed a more complete theory, including some dispersive effects related to fluid flow on a scale that encompasses many pores, providing modest differences between the velocities at the limits of low and high frequencies, of the order of 5% at its maximum, in extreme cases. However, at very high frequencies and in the presence of very viscous fluids, other dispersive effects in the pore scale may be relevant. These effects have been studied by many authors through what is generally known as local fluid flow and squirt flow models. Such effects are responsible for differences (or dispersion) between high and low frequency velocities from 10 to 20%, but there is still a lot of debate about the evidences that it would be active at the frequency bands involved in seismic or sonic logging methods.

Another problem that must be considered is associated to very viscous oils in reservoirs at low pressure and temperature, as these may present a non negligible shear modulus, violating the assumptions of the Biot theory (Vasquez et al., 1996). In these cases, probably the most appropriate approach is to apply effective media models to predict the fluid effects. Few studies look into the possible errors involved in applying Gassmann or Biot in these extreme cases. Makarynska et al. (2008) predicts errors as large as 70% on velocity prediction for viscous oil saturated sands.

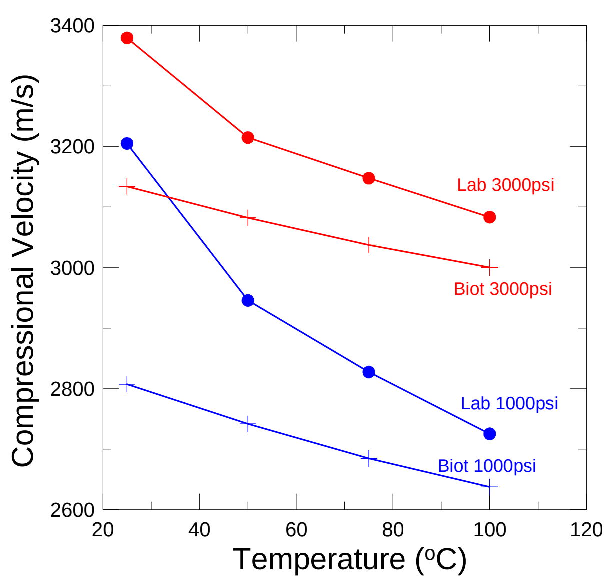

***Figure 5** – Compressional-wave velocities measured for an oil saturated sandstone sample from Dom João field in the laboratory (dots) at two differential pressures (1000 psi, in blue, and 3000 psi, in red) as a function of temperature, along with the Biot theory predictions for the high frequency limit (crosses).*

Laboratory studies have shown velocity differences of 15% for the Fazenda Alvorada and Dom João Fields. Figure 5 evidences an example for the compressional-wave velocity of a rock sample measured at 500 kHz in laboratory and the predictions of the high frequency boundary from the Biot theory. The difference between theory and experiment drops with increasing temperature, due to the reduction of oil viscosity, but a large residual difference still exists even at the temperature of 100 ^{o}C.

Discussion

Some common assumptions adopted on time-lapse seismic studies, particularly those related to reservoir stress and saturation conditions, may lead to erroneous estimations.

The main questions addressed in this work may be summarized as:
In situ stress anisotropy – seismic velocities are function of the average stress acting on the rock, which can imply large differences from the overburden stress in some cases;
Asymmetry of the reservoir seismic response to pore pressure depletion/increase – the reservoir response to stress can deviate significantly from that one observed on laboratory based on dry rock measurements;
Effective stress – in some rocks the differential stress is very different from the effective stress, so that the pore pressure effects may be not so pronounced as expected;
Patchy saturation – in cases where the heterogeneities on saturation distributions are relevant, we may consider to apply the patchy saturation scheme, it can also introduces apparent conflicts in log and seismic data due to the different frequencies;
Very viscous oils – the usual Gassmann's equations and even the Biot theory predictions might fail in the presence of very viscous fluids.

The effects of each one of these issues are strongly dependent of the type of rock (including consolidation degree), fluid, overburden and changes experienced by the reservoir. For example, loose sands are more sensitive to stress changes and stress anisotropy, but may exhibit effective stress coefficients near to one. Errors as large as 20% can be observed in ordinary situations.

Conclusions

Despite the excellent results of the seismic monitoring technology applied oil field production there are some poor understandings related to the seismic properties of rocks and their variations due to the reservoir conditions evolution. The importance of those issues will vary depending on the specific history of each field and can even invalidate the achievement of reliable quantitative analysis. Such fact turns the evaluation of possible errors involved in this technique so important that it will evolve for further investigation in the seismic rock physics science.

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