Effect of net to gross on time-lapse seismic response in Campos Basin, Brazil

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Abstract

Quantitative time-lapse studies require precise knowledge of the pressure response of rocks sampled by a seismic wave. Usually this knowledge is obtained from measurements of ultrasonic velocities as a function of pressure. These measurements are typically made on reservoir sandstone samples. However, if the reservoir is composed of sand and shale layers, the response of shales as well as sands has to be taken into account. The pressure response of shales is quite different from that in sand: since shales have very low permeability, an increase of pore pressure in the sand will cause an increase of confining pressure in the intra-reservoir shale.

To estimate the effect of intra-reservoir shale on the time-lapse response to depletion or injection, we compute the combined seismic response as a function of net to gross (NTG – sand-shale proportion). This is done by applying Backus average using typical shale and sandstone stress sensitivity for an oil field located in Campos Basin, Brazil.

For a typical NTG of 0.6, there is an error of approximately 35% in reflection coefficient estimation if these shales are neglected. Consequently, not considering the small shales intra-reservoir may mislead quantitative 4D studies. We suggest expanding this approach to 3D models in order to incorporate other geomechanical effects.

Introduction

The main aim of time-lapse seismic monitoring of oil and gas production is to map changes in fluid saturation and pressure in the reservoir zone. This requires the knowledge of the effect of saturation and pressure on elastic properties of rocks. Saturation effects on elastic properties are modeled using Gassmann equations (Mavko et al., 1998). Pressure effects are usually obtained from ultrasonic measurements on core samples (Nes et al., 2002), which can provide accurate estimates of the in situ stress sensitivity if the reservoir rock is sufficiently homogeneous (Grochau and Gurevich, 2008).

A limitation of this approach stems from the fact that laboratory measurements can only be done for a small number of core samples, which often represent 'good' reservoir rock (say, sandstone). However real reservoirs often are heterogeneous on a sub-seismic scale: in a addition to reservoir rock, they also contain non-permeable layers, most typically, shales. The pressure response of shales is quite different from that in sand. However, the seismic only cannot see individual sand or shale layers; it is defined by the properties of a package on the scale of seismic resolution. Modeling of this combined pressure response of sand/shale package requires the knowledge of the response of shale as well as sand.

The aim of this work is to alert to the impact of the intra-reservoir thin shales mechanical behavior to predict and interpret stress changes derived from production or injection. We propose a workflow to compute the reservoir combined response as a function of net to gross (NTG). The main idea is to consider the reservoir's intra-shale expansion or contraction in reaction to the sandstone hardening (depletion) or softening (injection). Because shale has very low permeability, the pore pressure in the shale may not have enough time between seismic surveys to equilibrate with the pressure in surrounding sands (MacBeth, 2007). In such cases the shales may be considered as impermeable. This is an approach that we take in this paper.

To evaluate the magnitude of thin shale layers on the reservoir's stress sensitivity response, we apply the developed workflow to a typical clastic reservoir located in Campos Basin, offshore Brazil. The importance of this effect for correct quantitatively modeling 4D effects in Brazilian oil fields may be significant. The majority of known Campos Basin mature reservoirs undergoing development are comprised of sandstone turbidites (Bruhn et al., 2003), and they often contain thin intra-shale layers. Disregarding the net to gross effect may bias results for frequently repeated surveys and even give the wrong sign of the 4D effect.

Effect of thin shale layers intra-reservoir during production

Consider a reservoir interval composed of a sequence of hydraulically communicated sands and nearly impermeable shales. During production, fluid pore pressure in the sandstone is reduced, increasing the effective pressure. Consider that there is no fluid communication between shales and sands during a period of time corresponding to frequently repeated 3D surveys. As there is no time for fluids to move between shales and sands in order to equilibrate pressure, the stress conditions will change only due to the mechanical pull caused by neighboring depleting sands. Consequently, during depletion the pore pressure will decrease in sandstones and stiffen these rocks (hardening), whereas the surrounding shales will mechanically expand (softening). Fluid injection into sand will cause the opposite effect: pore pressure in sand will increase causing its softening and consequently the hardening of the shales.

Computing elastic parameters to equivalent medium

To quantify the effect of the extension and contraction induced by stress changes, we consider the vertical P-wave propagation through the stack of shales and sands for different NTG in the reservoir interval. In this study we assume that the induced stress change in the shales has the same magnitude as, and the opposite sign to, the stress change in the sandstone: $\delta P_{shale} = -\delta P_{sand}$.

To estimate velocity dependence on pressure we use the equation (Eberhart-Phillips et al., 1989; Shapiro, 2003):

$$V(P) = A + KP - B\exp(-PD) \qquad (1)$$

where V is the P-wave velocity, P is the effective stress, A, B, K and D are fitting parameters for the set of measurements.

The elastic moduli of the sand/shale package are computed using Backus averaging (Backus, 1962; Mavko et al., 1998). The long-wave equivalent P-wave modulus M_{av}^0 and density ρ_{av}^0 of the package before production can be written as

$$\frac{1}{M_{av}^0} = \frac{N}{M_{sand}(P)} + \frac{1-N}{M_{shale}(P)} \qquad (2)$$

and

$$\rho_{av}^0 = N\rho_{sand}(P) + (1-N)\rho_{shale}(P) \qquad (3)$$

After depletion or production we have

$$\frac{1}{M_{av}^1} = \frac{N}{M_{sand}(P+\Delta P)} + \frac{1-N}{M_{shale}(P-\Delta P)} \qquad (4)$$

and

$$\rho_{av}^1 = N\rho_{sand}(P+\Delta P) + (1-N)\rho_{shale}(P-\Delta P) \qquad (5)$$

where $M_{sand}(P)$, $M_{shale}(P)$, $\rho_{sand}(P)$ and $\rho_{shale}(P)$ are P-wave moduli and densities of sand and shales, respectively, at effective pressure P; N is the net to gross (sand-shale ratio). The superscripts 0 and 1 refer to times before and after production and $\Delta P = P^1 - P^0$ is effective pressure change between the two surveys.

A case study for a clastic reservoir in Campos Basin

We analyze the seismic combined response (1D) using real data from a clastic reservoir in Campos Basin.

In Campos Basin there are more than 40 oil fields from different ages, representing a variety of reservoir properties. Each field and each reservoir has its own characteristics in terms of lithology, grain size, and cementation. We analyzed rock properties from a clastic reservoir located in the south portion of Campos Basin, around 100Km off the coast of Rio de Janeiro (southeastern Brazil), in a water depth of approximately 700 meters.

In deep and ultra-deep water projects, it is important to avoid costly workovers; therefore programs of pressure maintenance are frequently used (Bruhn et al., 2003). Close to the water injector wells pore pressure can significantly increase, whereas in other positions it could decrease due to depletion, resulting in higher effective pressure. The sub seismic intra-reservoir shale layers can vary in thickness and content (NTG) (Figure 1). Considering the variation of NTG and the possible lateral variation of effective pressure within the reservoir, the understanding of the combined seismic response of small scale intra-reservoir shales may be essential for quantitative 4D interpretations.

The reservoir is comprised of gravel to sand rich lobes - mainly arkosic sandstone - from confined turbidities related to a Cretaceos Period (Santonian / Campanian) marine transgressive megasequence. This 45 meters thick reservoir is comprised by the amalgamation of turbidites intercalated by shale layers with thickness ranging from centimeters to several meters. After the discovery in 1984, oil production started in 1985 and the reservoir (hydraulically interconnected) has been depleted by natural water aquifer and water injection. There are 25 wells producing 29 API oil, permeability is 1500mD and temperature 89ºC. The current and forecast recovery factors are 38 and 55%, respectively, and reservoir monitoring is important to locate unswept areas and map pressure variations.

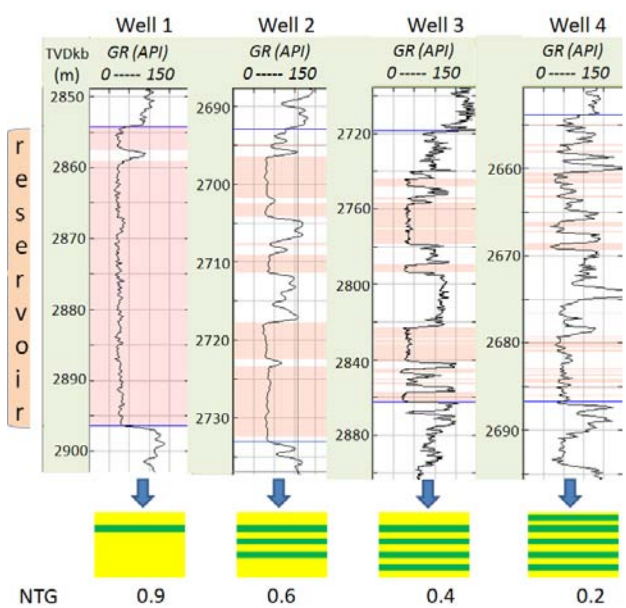

Figure 1: Gamma-ray logs over the reservoir interval for 4 wells located in an oil field in Campos Basin. The reservoir is comprised of sandstones (orange) and shales (white, GR>55).with composition (NTG) varying laterally.

Ultrasonic measurements were routinely done on sandstones and, in some cases, on shales to calibrate velocity sensitivity to pressure. A sinusoidal pulse with the central frequency 500 KHz was propagated through the sample and for each step of pressure increment velocities were determined from the travel time and the length of each sample.

The velocity-pressure dependence is obtained by fitting equation (1) to ultrasonic data using a nonlinear least squares regression (Figure 2). The fitting parameters A, B, K and D for the set of measurements are, respectively, $2.86{\cdot}10^3$, 6.40, $1.04{\cdot}10^3$, 0.205 for sand and $3.43{\cdot}10^3$, 0.0, $0.272{\cdot}10^3$, 0.0585 for shale.

We consider two production scenarios: injection and depletion. During injection, the pore pressure in the sand increases by $\Delta P = 10$ MPa, causing a decrease of effective pressure for shales by the same amount. During the depletion the opposite happens: pore pressure decreases: $\Delta P = -10$ MPa (Figure 2), causing corresponding increase of effective pressure on shale layers.

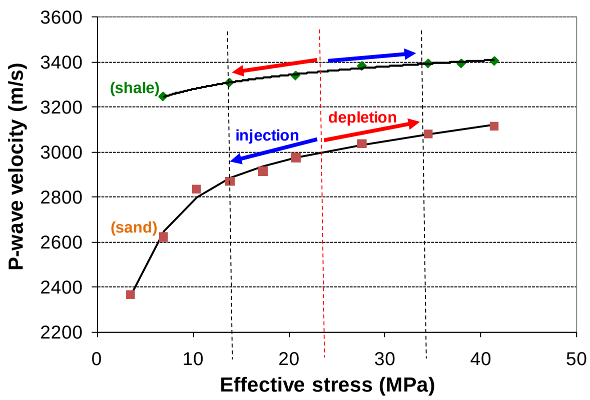

Figure 2: Velocity dependency on effective pressure from ultrasonic measurements for sand (brown) and shales (green). During depletion (red arrow) sand increases velocity (hardening) whereas shale decreases (softening). During injection (blue arrow) the opposite occurs.

From the original pressure condition, using equation (1) we compute new velocities for sandstone and shale for both scenarios: pressure increase (10MPa) and decrease (-10MPa). Using these velocities, we calculate average P-wave moduli (M_{av}) and average density (ρ_{av}) as a function of net to gross (equations (2) and (4)). In the range of stress considered, density is expected to vary by no more than 0.1% (Gurevich, 2004; Mavko and Jizba, 1991); thus it was assumed independent of pressure ($\rho^0_{av} = \rho^1_{av}$). Finally, impedances and reflection coefficients are obtained from P-wave moduli and densities for each net to gross increment.

Results

Figures 3 shows the expected P-wave impedance of a sand/shale package as a function of NTG for undisturbed conditions (black), and after depletion (red) and injection (blue) corresponding to change of pressure by ±10MPa. Impedances of this package increase for higher shale content since shale has higher impedance than sand. The rate of increase is higher for injection than depletion due to the shapes of the stress sensitivity curves.

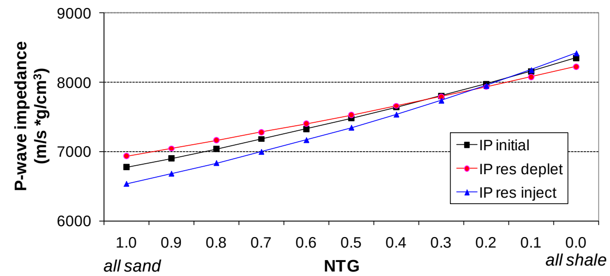

Figure 3: P-wave impedance of a heterogeneous (shales and sands) reservoir computed using Backus average. Depletion (red) and injection (blue) of 10 MPa from the initial (black) conditions are modeled as a function of net to gross.

The variation of impedance relative to the initial pressure condition as a function of net to gross is shown in Figure 4. In a depletion scenario (red line), hardening occurs in a reservoir made up only by sand (NTG=1). This is easily predictable since pore pressure is reduced, thus hardening the rock. When shale content increases (reducing NTG), the combined sand/shale impedance response decreases due to shale expansion, reacting to sand contraction. For NTG smaller than 0.3 the composite reservoir package changes the expected behavior: instead of hardening, softening happens even in a reservoir depletion scenario. For an injection scenario (blue line) the opposite occurs. These unexpected combined pressure responses could happen even for higher NTG for shales which are more sensitive to pressure.

Figure 4 also shows asymmetry in the impedance response during depletion and injection as pointed out by Sayers (2007). For a homogeneous sandstone reservoir (NTG=1) undergoing depletion, the impedance increases by 2.31%, whereas during injection it decreases by 3.53%.

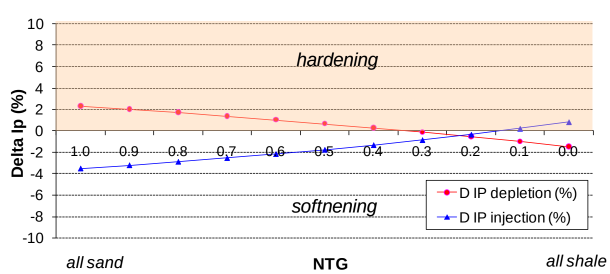

Figure 4: Relative changes in P-wave impedance (Delta Ip) relative to the initial pressure condition as a function of net to gross. Depletion (red) and injection (blue) of 10 MPa are modeled.

The impact of intra-reservoir shales on seismic data can be better understood by looking at reflection coefficients. Figure 5 shows P-wave reflection coefficients related to the top of the heterogeneous reservoir as a function of net to gross. Reflection coefficients become smaller (by absolute value) with the increase of shale content in the reservoir. The anticipated dimming effect on 4D data will be more prominent for a depletion scenario once the composite reservoir impedance will be more similar to that of the overburden rock. When we analyze changes in reflection coefficients due to shale/sand expansion and contraction, their correct magnitude (as shown in Figure 5 for stress sensitivities in this study) should be taken into account for quantitative time-lapse interpretation.

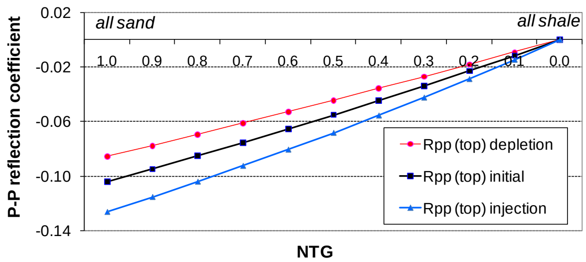

Figure 5: P-P reflection coefficients corresponding to the interface between the overburden shale and the heterogeneous reservoir. Depletion (red) and injection (blue) of 10 MPa from the initial (black) conditions are modeled as a function of net to gross.

Discussion and conclusions

Small scale intra-reservoir shales have a very different response to fluid injection and depletion from that of sand, and thus may have a strong effect on the equivalent properties of a heterogeneous sandstone reservoir. We propose a methodology using Backus average to compute the combined seismic response for depletion and injection scenarios as a function of net to gross. This approach is appropriate for modeling time-lapse effects in repeated seismic surveys when there is no time for pressure in shale and sand to equilibrate.

We apply this methodology using typical Campos Basin elastic properties. We conclude that impedances and reflection coefficients may be wrongly estimated without considering the presence of small scale intra-reservoir shales. The magnitude of the error in impedance estimation can vary from 3.5% to 0.8% (injection) and 2.3% to -1.5% (depletion), same magnitude of many expected changes in real 4D effects. Similarly, reflection coefficients could be largely misestimated if the presence of small scale intra-reservoir shales is ignored. Considering NTG of 0.6, for example, the correct value of the reflection coefficient is -0.053 instead of -0.086 (depletion), and -0.080 instead of -0.126 (injection). The differences are 38% and 36%, respectively.

The 4D response from the combined sand-shale reservoir can even be the opposite of expected. Instead of hardening during depletion, softening could occur. This unexpected behavior is more likely to happen for low NTG or in places where shales have higher sensitivity to pressure, as shallow layers.

Based on presented evidence of NTG effect on time-lapse response, we suggest this methodology be taken into account for quantitative time-lapse studies. We also suggest expanding analyses to 3D models to incorporate other geomechanical effects (like arching effects).

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