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Seismic Modeling In Reservoir Rocks

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ABSTRACT

Fluid flow in reservoir rocks can be traced by repeating seismic experiments over a certain time period. We model the change in characteristic seismic quantities, such as p-wave and s-wave velocities, in dependence of porosity and fluid content. Observing the influence of fluid flow properties on seismic wave propagation enables us to estimate the feasibility of seismically imaging fluid related quantities in reservoir rocks.

INTRODUCTION

Wave propagation in fluid saturated porous media can be described as being governed by Biot's equations of poroelasticity (Biot, 1956a+b). This theory explains the existence of a slow compressional wave in addition to the usual P– and S–Waves. The mode of this slow wave is a function of frequency. Below a critical frequency the wave is described using a diffusion term and above this frequency the wave moves like an elastic wave. Gassmann's (1951) equation is an exact formula for the poroelastic parameters in the low frequency domain if the solid matrix consists of only one type of constituents. This assumption is hardly satisfied in real geological settings and one is usually forced to use extensions of Gassmann's formula such as introduced by Brown and Korringa (1975). There extension describes conglomerates of two porous phases or how to build an averaged solid phase. For this study we used Hashin-Shtrikmann effective isotropic medium approach to construct such an averaged mineral phase. The aim is to evaluate how P– and S–wave velocity and V_P/V_S ratio change for varying porosity.

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COMPUTING THE EFFECTIVE MEDIUM

When a porous rock is loaded under an increment of compression, such as from a passing seismic wave, an incremental change in pore pressure is induced, which resists the compression and stiffens the rock. The increase in effective bulk modulus K_{sat} of a saturated porous medium is described by Gassmann's equation (Mavko et.al, 1998):

$$\frac{K_{sat}}{K_0 - K_{sat}} = \frac{K_{dry}}{K_0 - K_{dry}} + \frac{K_{fl}}{\phi(K_0 - K_{fly})} \tag{1}$$

and

$$\mu_{sat} = \mu_{dry}. \tag{2}$$

K_0 is the bulk modulus of the frame building mineral, K_{dry} is the effective bulk modulus of dry rock, e.g. the rock matrix, K_{fl} is the bulk modulus of the pore fluid, ϕ is the porosity, μ_{dry} is the effective shear modulus of the dry rock and μ_{sat} the effective shear modulus of the fluid saturated rock.

Murphy, Schwartz and Hornby (1991) formulated the velocity form of Gassmann's relation:

$$V_{Psat}^2 = \frac{K_p + K_{dry} + \frac{4}{3} \cdot \mu}{\rho_{sat}} \tag{3}$$

and

$$V_{Ssat}^2 = \frac{\mu}{\rho_{sat}} \tag{4}$$

with

$$K_p = \frac{1 - \left(\frac{K_{dry}}{K_0}\right)^2}{\frac{\phi}{K_{fl}} + \frac{1-\phi}{K_0} - \frac{K_{dry}}{K_0^2}}. \tag{5}$$

which allows a direct computation of quantities required for our modeling software. V_{Psat} and V_{Ssat} are the P–wave velocity and S–wave velocity in a saturated rock respectively and $\mu = \mu_{sat} = \mu_{dry}$.

The *dry* moduli refer to elastic moduli, measured in drained experiments with a constant pore pressure or an experiment with an air filled sample (Mavko *et.al*, 1998).

The Gassmann equation is often used to predict seismic velocities of saturated rocks from dry rock velocities and vice versa; or for rocks that are saturated with one fluid from rock velocities saturated with another fluid. The equation is valid for low frequencies such that the fluid has enough time to flow and equilibrate the seismic wave induced pore pressure gradients.

A REALISTIC EXAMPLE

The Alba Field in the Central North Sea serves as typical reservoir setting (MacLeod *et.al.*, 1999) in which we carry out feasibility studies. The Alba Field consists of Eocene-age, high-porosity, unconsolidated turbudite channel sands sealed by low-permeability shales. From the given density for oil-saturated and water-saturated Alba reservoir sand, a mean porosity of 30% and an assumed water density of $1\frac{g}{cm^3}$ the matrix mineral density and oil density under reservoir conditions are computed to be $2.53\frac{g}{cm^3}$ and $0.77\frac{g}{cm^3}$ respectively. The shear wave velocity $V_{S_{oil}}$ inside the reservoir above the oil water contact is given as approximately $1.341\frac{km}{s}$. This produces a saturated shear modulus for the Alba sand of 3.6 GPa. With a given V_P for oil-saturated and water-saturated reservoir sands, we are able to calculate the saturated bulk modulus. For oil-saturated sand it is 9.60 GPa, for water-saturated sand 13.17 GPa. The bulk modulus of water under reservoir conditions has to be assumed to 3.0 GPa, because we have no information about temperature, fluid pressure and salinity.

A sytematic parameter variation was carried out using Gassmann equation with porosity n as the independent variable. Figure 1 shows the result for water saturated and Figure 2 for oil saturated Alba sand.

The p-wave velocity V_P in oil-saturated is more sensitiv to porosity variation than in water-saturated sand. The most remarkable difference between the two pore fluids is the behaviour of V_P/V_S. While it is decreasing with increasing porosity for oil as pore fluid, it increases with increasing porosity, if water is filling the pore space. Such considerations ultimately allow to distinguish between different fluid types. Such investigation can also be used to determine the feasibility and effectiveness of fluid flow monitoring efforts. An example of simulating fluid flow is shown in figure 3. It shows the saturation destribution for an initially unsaturated porous medium filling up over time by a central well.

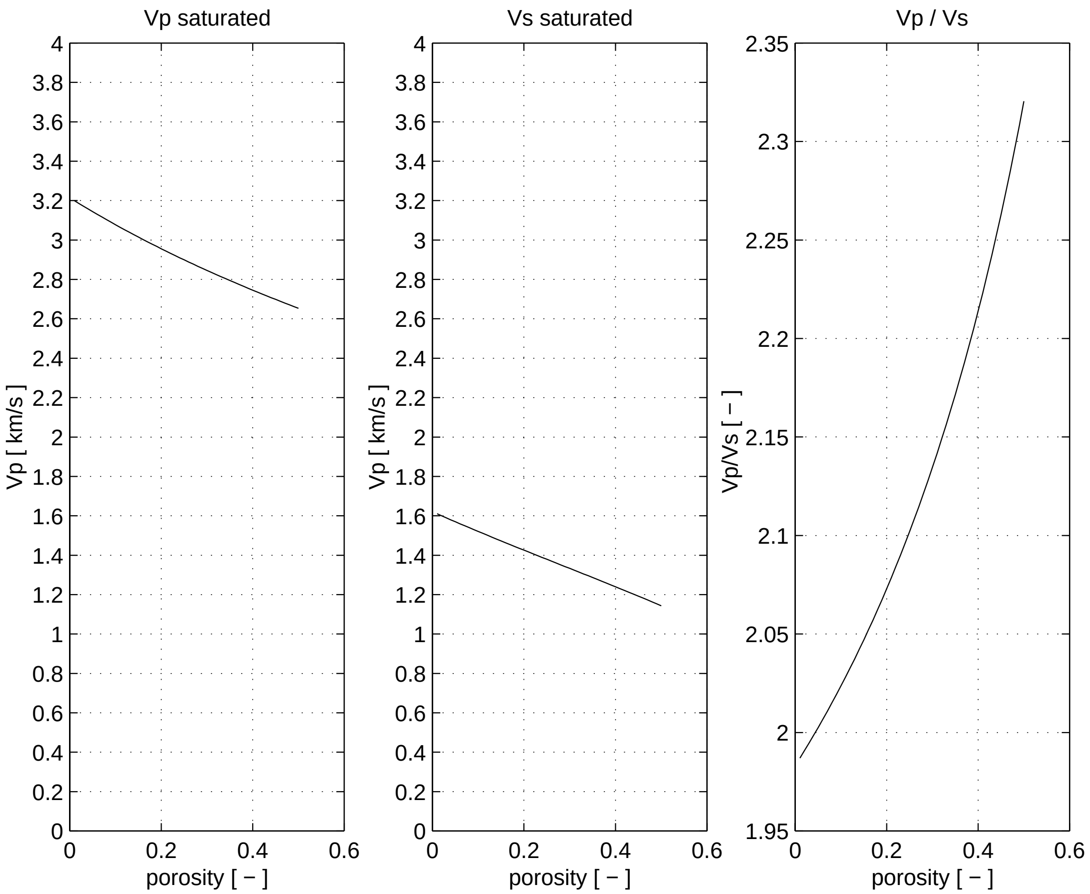

Figure 1: The dependence of P–wave velocity, S–wave velocity and V_P/V_S– ratio for water saturated Alba sand from porosity is shown. With increasing porosity V_P/V_S–ratio is increasing.

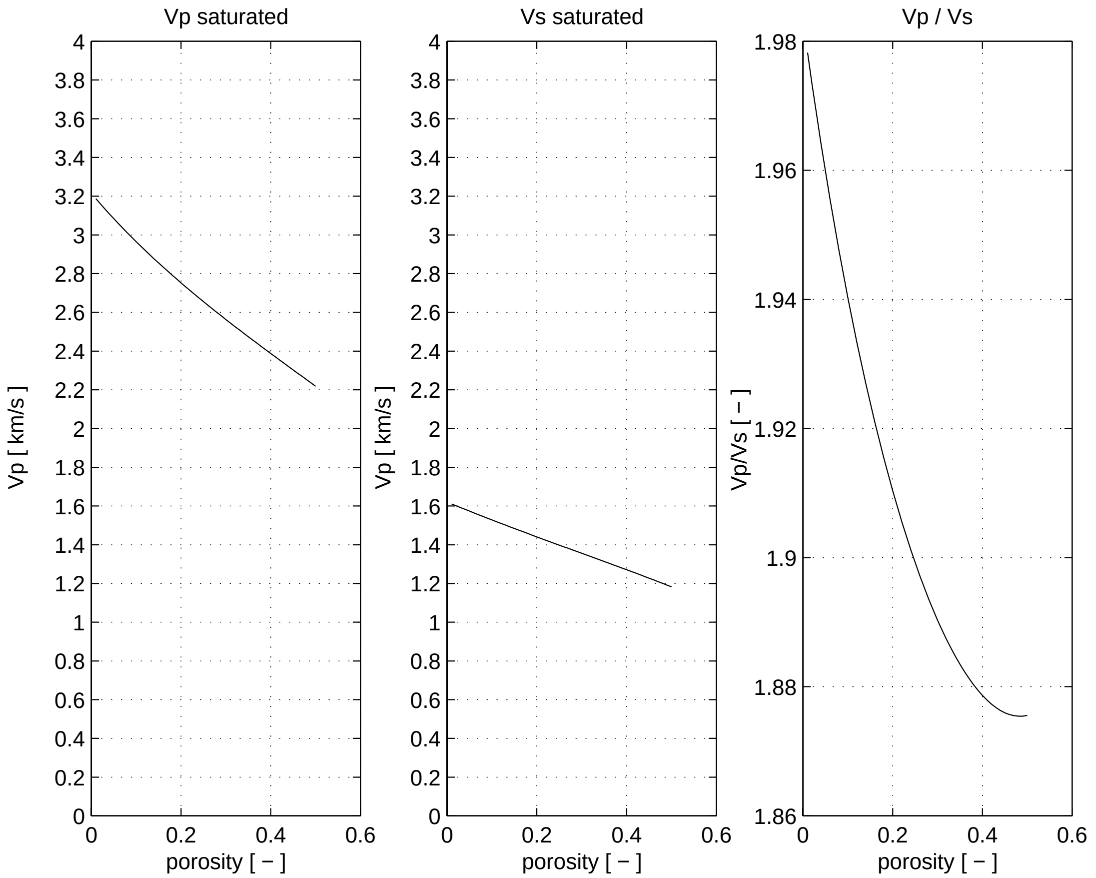

Figure 2: The dependence of P–wave velocity, S–wave velocity and V_P/V_S– ratio for oil saturated Alba sand from porosity is shown. With increasing porosity V_P/V_S– ratio is decreasing.

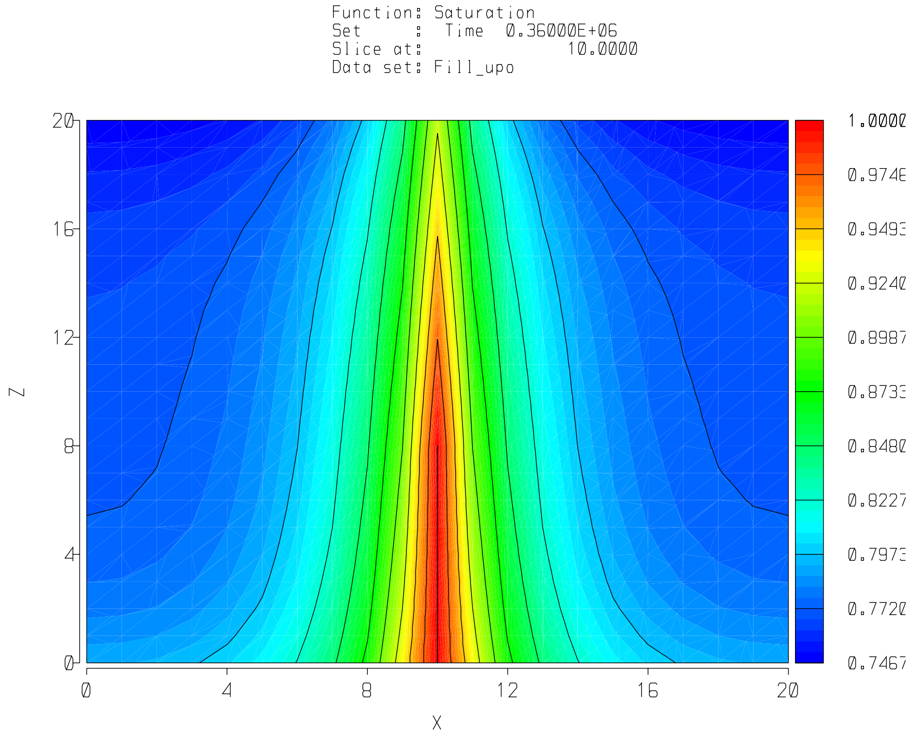

Figure 3: Time history of fluid saturation caused by a central injection well.

CONCLUSION

While our ability to perform fluid substitution for practical reservoir scenarios works well with the estabilished theory, we aim at testing more sophisticated substitution schemes, leading up to include ansiotropy and viscous damping. We can carry out full wave form seismic simulations of typical data acquisition scenarios by using Finite Difference Modeling techniques in 2D and 3D. In the future we plan to model wave propagation with 3D-finite difference scheme based on Biot's theory of wave propagation in fluid saturated porous media. For a realistic model we plan to model 3D fluid flow behavior and pore pressure distribution with a fluid flow simulator. The combination of theory and numerical techniques allows us to perform sophisticated studies in the near future.

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