Reducing uncertainties in saturation scales using fluid flow models

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Summary:

In this paper we present a multidisciplinary study quantifying how scales of saturation can introduce uncertainties into interpretation of seismic attributes for hydrocarbon detection, and how knowledge of fluid dynamics from flow simulators can help to reduce the uncertainties.

Introduction:

The sensitivity of seismic velocities to pore fluids has been recognized for years (Gassmann, 1951; Nur, 1969). Less widely known is that seismic velocities depend not only on the types and saturations of the pore fluids (water, oil, gas), but also on the spatial scales of heterogeneous fluid distributions (White, 1975). Spatially varying saturations give rise to wave-induced pore pressure gradients, which in turn cause wave attenuation and velocity dispersion (Akbar et al., 1994).

Figure 1 shows the dependence of seismic velocity on fluid saturation for two different scales of saturation. We observe from this figure that, given an observed seismic velocity of 2.35 km/s, the oil saturation could be 99% with a fine-scale or homogeneous distribution, or 20% with a coarse-scale, patchy distribution. There is a large uncertainty in interpreting the oil saturation. Is it 20% oil, or 99% oil, or somewhere in between?

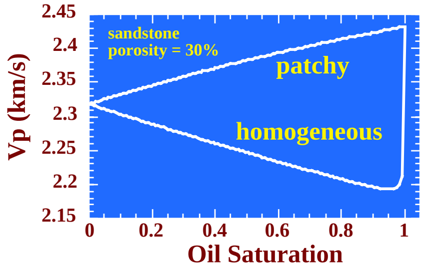
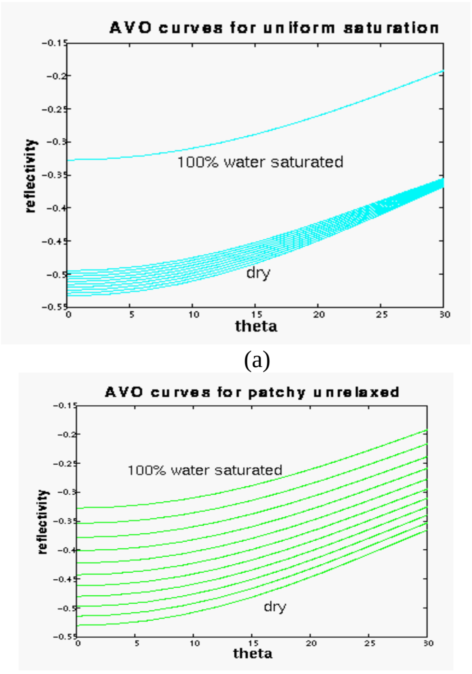


Figure 1: Velocity depends on fluid saturation, as well as on the saturation scales.

Figure 2 shows another ambiguous scenario. The AVO curves of two rocks are plotted. They have identical mineralogy, porosity, pore-fluids, density, and overburdens. The only difference is the scale of fluid saturation. Figure 2 (a) shows the AVO response of a rock for different values of water saturation, ranging from 0 to 100%. The saturation distribution is uniform, or fine scale. Figure 2 (b) shows the AVO response of a rock which is exactly the same, except that the scale of fluid saturation here is coarse, or patchy.



(a)

(b)

Figure 2: Ambiguity in AVO interpretation caused by different saturation scales.

Theory:

When the size of the fluid patch in the reservoir is significantly smaller than the seismic wavelength, the individual patches cannot be resolved, but they still influence velocity and impedance. Sub resolution patches are divided into two ranges dictated by D, the hydraulic diffusivity, and L_c, characteristic diffusion length of the medium. The diffusion length can be estimated approximately as shown in equation

$$L_c \approx \sqrt{D/f}$$

where f is the frequency of the seismic wave. The two different saturation scales we address in this paper are:

- $d<L_C$, uniform saturation
- $d>L_C$, patchy saturation

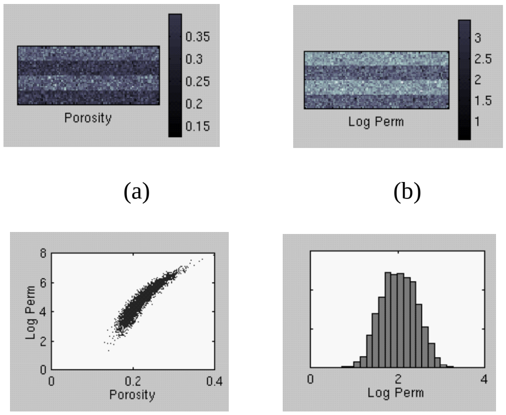
Here, d is the characteristic saturation scale, or "patch" size. In case of uniform saturation, the seismic velocity is given by putting the Reuss average fluid (obtained by averaging fluid compressibilities) or "effective fluid" (Domenico, 1976) into Gassmann's equation. This is the typical approach commonly used for fluid substitution. In case of patchy saturation, this model is no longer valid. Instead, when each of the phases is well separated over scales $>L_C$ the effective moduli of the rock can be estimated with the equation from Hill (1963):

$$\frac{1}{K+\frac{4}{3}\mu}=\left\langle \frac{1}{K_{sat}+\frac{4}{3}\mu} \right\rangle$$

where K and μ are the effective bulk and shear moduli of the rock, K_{sat} is the saturated rock bulk modulus within each of the saturation patches (water, oil, and gas) computed with Gassmann’s relations, and $\langle\ \rangle$ designates a volumetric average.

Method:

We stochastically generated porosity and permeability fields, shown in Figure 3, which are related to each other by the Kozeny-Carman relation. Each grid block is about the size of the characteristic diffusion length, since any saturation heterogeneities smaller than this scale will appear homogeneous to the seismic wave.



(a) (b)

(c) (d)

Figure 3: Stochastically generated porosity field (a) and permeability field (b). (c) is the cross plot of porosity versus permeability. (d) shows the log-normal permeability.

We performed fine scale flow simulations using Eclipse, which is a fully-implicit, three phase, three dimensional, general purpose black oil simulator. We investigated the relative importance of different geological and flow parameters, such as permeability relative permeability of the fluid phases, wettability, and fluid properties, in determining saturation scales From the saturation patterns obtained from the flow simulation results, we constrain the saturation scales, and therefore try to reduce the uncertainty in interpretation of seismic velocities and reflectivities in terms of fluids.

Examples:

We studied two broad cases, waterflooding an oil reservoir, and gas injection into an oil reservoir. For both these cases we tried to find the reservoir and fluid parameters that were important in determining the scales of saturations.

Waterflood:

We studied the saturation patterns obtained by waterflooding a reservoir, which was initially saturated with oil. The saturations patterns were then mapped onto seismic velocities by using Gassmann's equation to calculate the velocity at a pixel, and then by using Hill's equation to calculate the average velocity of the entire block.

A key parameter that impacts the saturation scales is the relative permeabilities of the fluids in the reservoir. The solid lines in Figure 4 show the relative permeabilities of oil and water in the reservoir. The reservoir rock is water wet. The relative permeability of a phase is typically a function of saturation of that phase in the rock. These relations are inputs to the flow simulator. Relative permeabilities are usually measured in the lab, at the core scale.

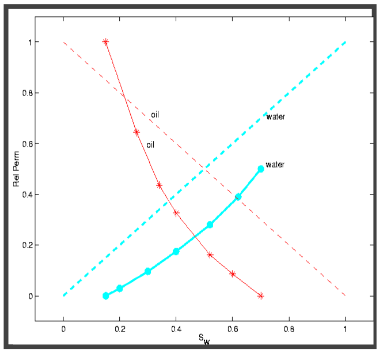


Figure 4: Relative Permeability curves used in Flow Simulations. Solid lines: Figure 5(a), Dashed lines: Figure 5(b).

Saturation scales

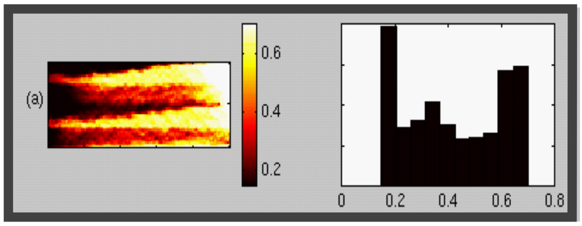


Figure 5 (a) : Saturation Map and Corresponding Histogram of Water Saturations Obtained by Flow Simulation. An Oil Producer is on Left of Reservoir and a Water injector on Right

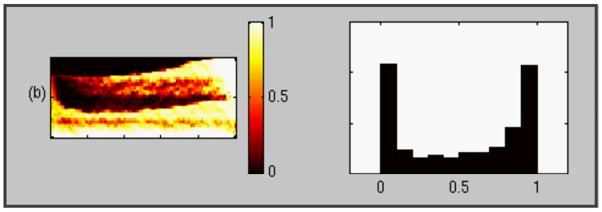


Figure 5 (b): Saturation map obtained from Flow Simulations by using the dashed Relative Permeability curves shown in Figure 5. We see from the image as well as from the histogram, that there are now patches of pure oil and pure water in the reservoir.

Figure 5 (a) shows the distribution of the two fluid phases after water flooding the reservoir for 150 days. We can see that water has preferentially entered the high permeability layers. The fluid saturations appear visually "patchy", since we observe that the fluid is distributed in fairly large patches of "mostly oil" and "mostly water". The important question here is, does the seismic velocity of this reservoir fall on the "patchy" curve?

To understand the seismic response of this heterogeneously saturated rock, we need to understand that the patchy and homogeneous curves are two extremes, or bounds, and the saturation can be somewhere in between these two extremes. For example, if we have coarse scale patches of water and oil, but if the water patches have some oil in them, then the saturation is, in fact a combination of both fine (uniform) and coarse (patchy) scales. This is because the coarse scale patches contain some fine scale heterogeneities in them. The seismic velocity, in this case, is no longer on the original patchy curve. The velocity will deviate from the "patchy" curve toward the homogeneous curve. The exact value will depend on how much oil is present in the water patches.

We need to refer to the histogram of the fluid saturation in Figure 5 (a). The minimum water saturation here is about 20% and the maximum is about 70%. Thus, we can now say that it is unlikely to find patches of pure water or pure oil in the reservoir. We may find patches of 70% water and 20% water, but the seismic response is very different from the strictly patchy curve that we are familiar with.

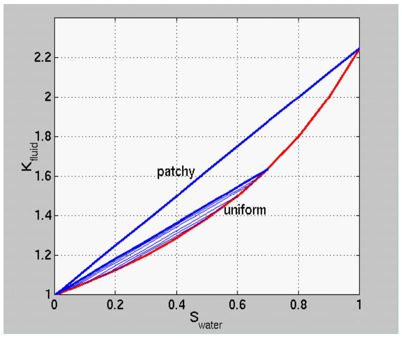


Figure 6: Uncertainties due to saturation scales can be reduced by a knowledge of fluid flow in heterogeneous reservoirs.

Figure 6 shows that a knowledge of flow simulation results can reduce the uncertainty in interpreting fluid saturations. For an observed fluid bulk modulus of 1.6 GPa, the uncertainty due to saturation scales is quite large. It could range from uniform saturation with 70% water at one end to patchy saturation with 50% water at the other. If we consider the first flow simulation results, shown in figure 5 (a), we observe that the water saturation does not rise above 70% at any point in the reservoir. This value corresponds to the irreducible oil in the rock, which is 30%. Knowing this, our bounds collapse very close together. Now, the end member on the "patchy" curve is no longer water, but is a homogeneous mixture of 70% water and 30% oil. Now, for the same observed K_f, the uncertainty due to saturation scales reduces a lot. We can interpret the water saturation to be between 69-70%.

Next, we examine the effect of wettability of the rock on the saturation scales. We repeat the same waterflooding with the same initial conditions, but now we consider the case where the reservoir rock is oil wet.

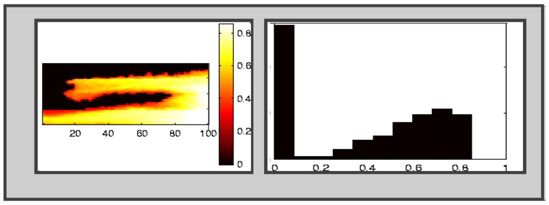


Figure 7: Saturation pattern and corresponding histogram obtained by waterflooding an oil-wet reservoir initially saturated with oil.

Saturation scales

The wettability of the rock in fact affects the relative permeabilituy curves. The result of waterflooding an oilwet reservoir is shown in Figure 7. Waterflooding an oil-wet rock is a "drainage" mechanism according to the convention of the Petroleum Engineering literature, while waterflooding a water-wet rock is "imbibition".

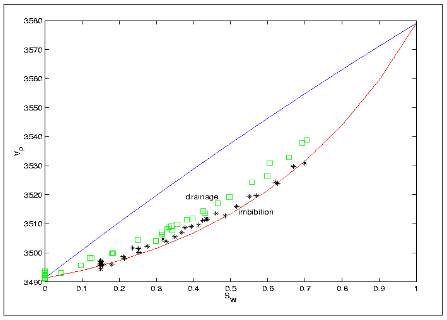


Figure 8: The seismic velocities of the oil-wet and water-wet reservoir during waterfloods. Waterflooding a water-wet rock is an imbibition process. Waterflooding an oil-wet rock is drainage.

From Figure 8, which shows the seismic velocities obtained by waterflooding the two different kinds of rocks, we observe that wettability of the rock is a factor which affects the "patchiness" or the scale of the saturation. These results conform to experimental results obtained by Knight, and by Cadoret, in which the saturation tended to be patchy during drainage, and uniform during imbibition.

Gas injection:

We repeated the same procedure with the same initial conditions (oil saturated rock) but now the injected fluid was gas instead of water. Figure 9 shows the saturation patterns and histograms of the saturation maps obtained at different time steps during gas injection. We see that the density contrast of the fluids plays a great role in the saturation scales. Gas being much lighter than the oil, stays at the top of the reservoir, forming a gas cap. We see from the histogram that there are large patches of pure oil and almost pure gas, which indicates seismically "patchy" behavior. Another factor which will favor patchy behavior is that in this case, the gas is the non-wetting fluid, and this process is therefore a drainage process.

Figure 10 shows the seismic velocities obtained from the saturation maps. The pixel velocities are computed using Gassmann and the velocity of the block is computed using Hill's equation. The saturation range is spanned by taking the saturations at different timesteps.

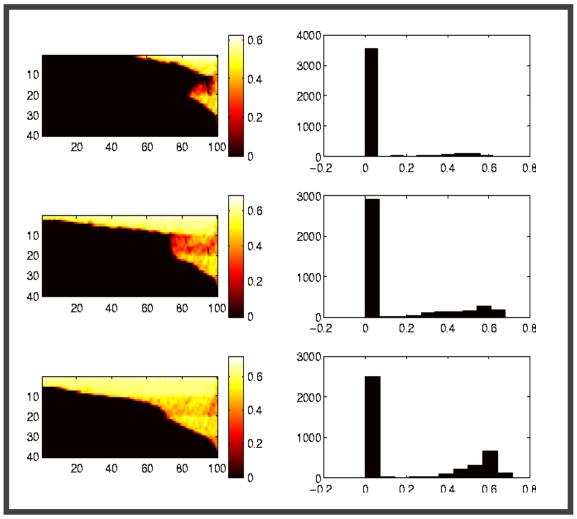


Figure 9: Saturation patterns at different time steps obtained by injecting gas into an oil-saturated reservoir.

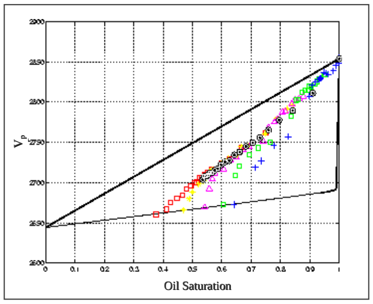


Figure 10: Seismic velocities of the initially oil-saturated reservoir during gas injection.

Conclusions:

Flow simulations have helped us to understand what factors can determine the scales of saturation. Factors which appear to influence "patchiness" of the fluid distribution, are the permeability distribution, the relative permeability of the fluids, the irreducible saturations, the density contrasts of the fluid phases, the wettability of the rock, and the fluid properties. We are more likely to observe "patchy" behavior when there is gas in the reservoir, rather than only oil and water.

Acknowledgments:

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