

Fluids, AVO, and seismic amplitudes: field examples

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Summary

This paper presents the results of two field cases where the effects of rock and fluid properties on seismic response are illustrated. The first case is an example from the North Sea that shows how small errors in shear wave velocity prediction affect forward modeled AVO response. Case 1 also shows the effect of replacing hydrocarbons with brine. The second case illustrates how rock and fluid properties along with reflection amplitudes can be used to estimate fluid type in an off-shore Gulf of Mexico fault block.

Introduction

The effects of fluids and rock mineralogy on seismic velocity are well known in principle. However, quantitative results that show the specific effects of fluids and rock type on seismic are less common. These two cases illustrate that seismic response to changing fluid properties can be quantified and that a detailed analysis of the rock and fluid velocities and densities can be used in interpretation.

Case 1: V_s Prediction and Fluid Substitution

This example is based on a well from the North Sea. This well contains a hydrocarbon bearing zone from about 8712 ft. to 8820 ft. Log data indicated a gas/oil contact at about 8775 ft. A full suite of logs was run allowing for a multiple mineral analysis. In addition, a dipole sonic log was run which allowed us to compare measured to predicted shear wave velocity. From the logs, we were able to construct a four layer model for

the pay zone and its over- and under-lying horizons (left side, Figure 1). From this model, a synthetic seismic

TABLE 1. Fluid properties, Case 1

Property	Value
Brine salinity	50,000 ppm
Oil API gravity	25
Gas/Oil ratio	520 scf/bbl
Gas gravity	1.0
Dissolved gas in brine	0

section was generated using commercial 2-D modeling software (right side, Figure 1).

Table 1 summarizes the reservoir fluid properties. Average fluid saturations, minerals volumes and porosities are shown in Figure 1. The physical properties of the water, oil, and gas were obtained with commercial rock physics software using relations presented by Batzle and Wang. Properties of the fluid mix for the pay zone were computed by the “patchy” fluid saturation model of Packwood and Mavko. Shear wave velocity was then predicted for the entire log using the Greenberg and Castagna model. This “best” V_s prediction was then used to model the AVO response in layers 2, 3, and 4. The new synthetic seismic using the computed V_s values are shown in Figure 2. The results are virtually identical to those in Figure 1.

Next we assumed that the fluid was brine and the mineralogy was clean sand (roughly equivalent to assuming Poisson’s ratio is 0.25) and recomputed V_s in layers 2, 3, and 4. We then performed the same synthetic seismic routine and the results are shown in Figure 3.

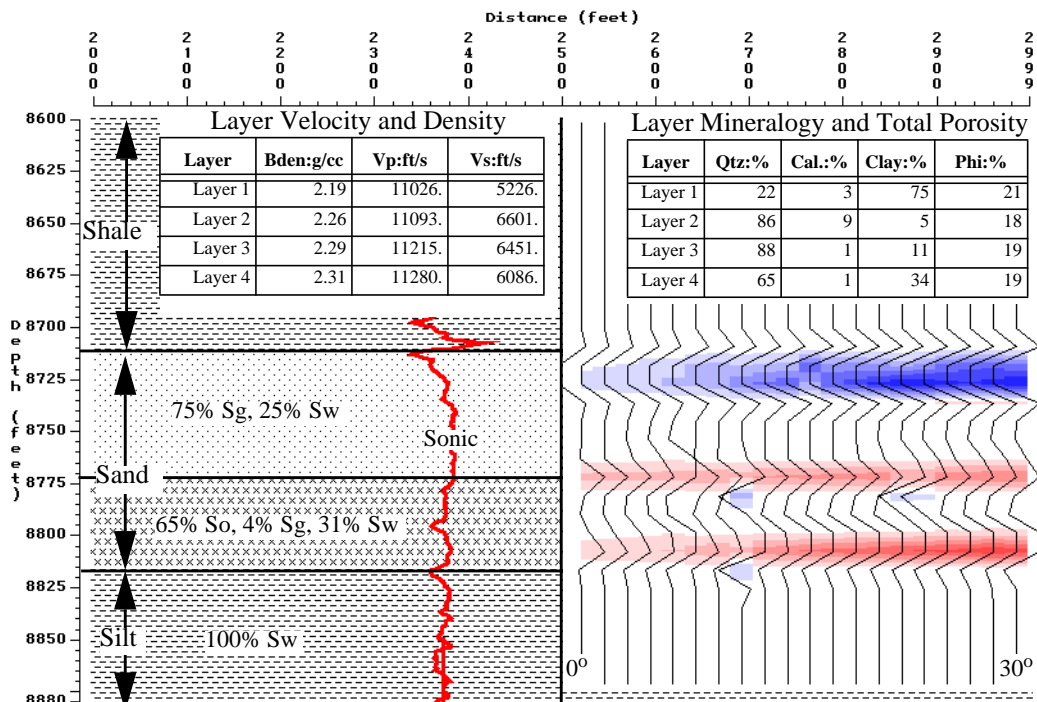
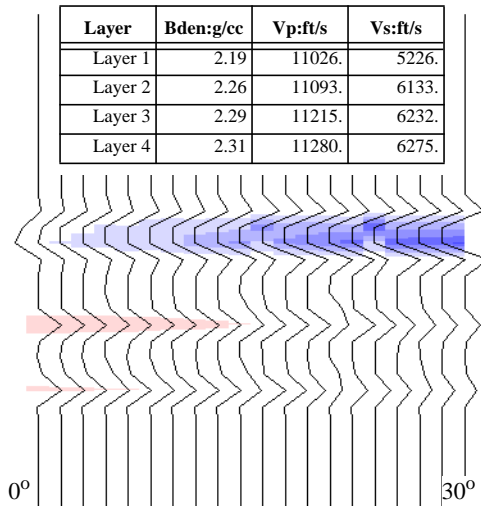
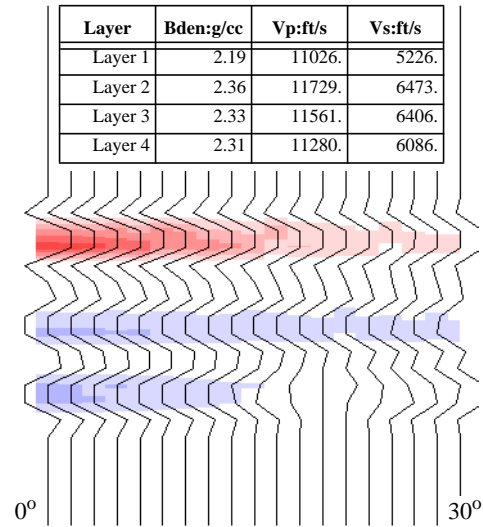
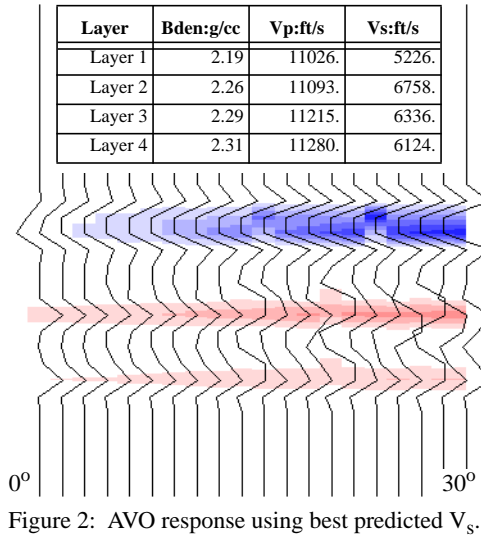


Figure 1: Model and synthetic seismogram, North Sea example.

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Compared to the original case, we see that the near offset response is very similar, but as the offset increases (to a maximum of about 30 deg.), the reflection amplitudes decrease for the lower two layers instead of increasing. This highlights the importance of having accurate shear velocity values for all layers of the model.

Next, we computed new V_p , V_s , and density values for the pay zone assuming that it was completely water saturated. The synthetic seismic (Figure 4) shows a major change in character at all offsets. The polarity of the reflections are completely reversed indicating that the hydrocarbons are a major factor in this model, as opposed to simply changes in lithology.

Case 2: Predicting Fluids from Seismic Amplitudes

A problem often encountered in exploration and development geophysics is to estimate the fluid type in prospects based on amplitude information in seismic data. This example shows the application of rock and fluid properties analysis in predicting fluid type in an untested fault block of a Gulf of Mexico sand. Figure 5 is a time structure and seismic amplitude map of the Late Pliocene horizon.

The hydrocarbons in fault block 1-3 varied from dry gas to medium weight oil. The goal was to estimate the hydrocarbon type in prospective fault block 4. The method was to use data on sand velocity, density, porosity, clay content and expected fluid types as input into the rock physics software for estimation of acoustic impedance and reflectivity for various types of hydrocarbon saturants. By comparing the computed hydrocarbon to wet reflection coefficients ratios to the observed seismic amplitude ratios of the known hydrocarbons to wet sand, a prediction was made of the pore fluid in untested fault block 4. The input data is shown in Table 2.

The "weakly cemented sand" model of Dvorkin, et al. was used to adjust the clay/sand ratio and total porosity until the lithology was consistent with the measured velocity and density of the sand. The Dvorkin model was used to get V_p and density for two weights of oil and for dry gas. V_s was found using the Greenberg-Castagna method. Using well logs to obtain average acoustic impedance for overlying shales, reflection coefficient ratios of hydrocarbon to wet saturation were computed. Actual ratios also were obtained from the seismic amplitude maps.

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The wet amplitude reference was chosen from the map at the base of the steep amplitude gradient adjacent to the bright spots just across the presumed hydrocarbon/water contact. Table 2 shows the results.

Fault block 1 contains a known thin gas sand, fault block 2 contains a thick dry gas sand, fault block 3 contains oil of API 32, GOR~550, and fault block 4 is an unknown prospect. Notice that amplitude ratios are approximately explained by simply varying the fluid type and not the lithology. For example, the computed amplitude ratio for the oil-sand/wet-sand interface is 2.25 compared to 1.77 from the seismic map. The computed ratio for the gas-sand/wet-sand interface is 2.81 compared to 2.86 for the seismic map. The computed ratio for the oil sand has greater uncertainty because the GOR varies considerably in the field oil sand.

On this basis, and taking into account the risk associated with sand thickness, the pore fluid in prospective fault block 4 was predicted to be a higher GOR oil than the oil found in fault block 3. If the sand encountered in fault block 4 is thin (<65 feet), then gas or a gas cap on oil is possible. However, a thin sand is not expected at the prospect for stratigraphic reasons. In general, the modeled rock properties and the observed amplitude extraction results suggest that oil sands are expected to be approximately 1.5 to 2.6 times the wet amplitude and gas sands are expected to be approximately 2.4 to 3 times the wet amplitude.

After this analysis was done, Fault block 4 was drilled. The well was perfed in 200 feet of the lower zone of the sand and is now producing dry gas. This zone has good density-neutron porosity crossover. In the upper zone which is mainly responsible for the reflection response we measured, there is no crossover and the petrophysicists feel sure it is oil. It will be produced later when the lower zone is depleted. There is a shale break between the two zones to compartmentalize them.

Conclusions

These two examples illustrate that quantitative interpretation of fluid type can be made based on computed rock properties and seismic data. They also show the importance of fluid properties and lithology on prediction of shear wave velocity, AVO response, and reflection amplitudes.

Acknowledgments

The author would like to thank Mobil Oil Company for providing log data to the SEG AVO Workshop, 1994 (Case 1). The contribution of data and analysis in Case 2 is also gratefully acknowledged to Unocal Corp.

Thanks also to Don Larson of GX Technology for many helpful tips on seismic modeling.

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Table 2: Rock properties and seismic amplitude ratios. (Sand por. 2.5-28%, ave. Sw 30%, ave. depth 5000 ft., GOR 400-700 scf/bbl, API 31-32, gas grav. 0.6, temp. 132 F, 9.6# mud. Velocity, density, and R.C. ratio computed, Amp. Ratio from seismic)

Lithology	Vp:ft/s	Vs:ft/s	Bden:g/cc	R.C. ratio	Amp. Ratio
Wet sand	8335	4067	2.01	1	1
Field oil sand, ft. block 3					1.77
Model oil sand, GOR 550	7465	4193	1.89	2.25	
Model oil sand, GOR 1K	7418	4219	1.87	2.39	
Thin gas and, ft. block 1					2.41
Prospect, ft. block 4					2.5
Modeled gas sand	7748	4443	1.69	2.81	
Field gas sand, ft block 1					2.86