Calibrated Three-term AVO to Estimate Density and Water Saturation

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Summary

There is great interest in the exploration communtity in three-term AVO inversion and in particular the potential for density reflectivity to provide additional information about fluid saturation. The incorporation of density information makes the estimation of fluid saturation better posed, however the relationship between the elastic and rock properties is still complex. This paper outlines a methodology to qualitativelly estimate, from calibrated three-term AVO analysis of seismic data, reservoir properties such as porosity, lithology, pore fluid type, and pore fluid saturation. This is demonstrated by a case history discriminating water saturation in a shaley sand using three-term AVO analysis of seismic data.

Introduction

The relationship between elastic properties and rock properties is complex. Including density, there are only three unique reflectivity attributes that can be estimated from the seismic. In constrast, the rock and fluid properties are influenced by a myriad of parameters. This makes the estimation of rock and fluid properties from AVO reflectivity attributes non-unique. Usually the problem is worse than this, since due to noise considerations, only two AVO reflectivity attributes are typically estimated. This paper follows the three-term AVO inversion of Downton and Lines (2001) where geologic constraints based on the available well control are incorporated to help stabilize the solution. The amount these constraints contribute to the solution is dependent on the noise-to-signal ratio and the geometry of the problem. As the data gets noiser, the constraints contribute more to the solution.

To help understand the complex relationship between the rock and fluid properties, and the elastic parameters the first part of this paper follows the methodology of Chaveste (2003A). First a petrophysical analysis is performed to establish the rock and fluid properties. Then the velocities and densities are related to the petrophysical properties of interest through well log modeling, which allows well log reconstruction for different reservoir conditions. The reconstructed logs are used to compute rock properties at well log resolution, for different reservoir conditions, allowing sensitivity analysis of various rock properties to different reservoir conditions. Sensitivity analysis at *seismic* resolution is then done by using the reconstructed logs to generate pre-stack synthetic seismograms from which rock properties are computed. After evaluating well-modeling and seismic-modeling results, rock properties are computed from recorded seismic data and evaluated based on observations made in the modeling.

When water saturation estimation is of interest, one important rock property to consider is density, since, unlke P-wave velocity, density changes linearly with water saturation. This calls for a three-term AVO analysis of the recorded seismic; density reflectivity being the third term. The approach incorporates real-world calibration of seismically-derived rock properties to well log data, directly linking predicted properties to direct measurements.

A case history is shown where a three-term AVO inversion has been performed in which the predicted density matched the actually density found on the well logs. In this case, the density by itself does not uniquely identify commerical hydrocarbons because of the variability of the reservoir. However, with the aid of well log modeling, it is found that the three elastic parameters predicted by the AVO inversion are sufficient to describe the reservoir and hydrocarbons.

Method

Determining accurate relationships between volume fractions of constituent phases of rocks and their P- and S-wave velocities and densities is critical, as these relationships link the petrophysical property under investigation to the observed seismic response. Following the approach described by Chaveste (2003A), petrophysical evaluation is performed to obtain shale, sand and/or carbonate volume fractions based on either the Gamma Ray or SP logs. Total and effective porosity are calculated from the available logging suite. Log porosity is calibrated to core porosity if required. Porosity and permeability relationships are computed as required by the project. Water saturation is calculated using Archie, or other petrophysical model. Net pay cutoffs and net pay reservoir parameters in the wells are estimated.

The second stage is well modeling. In this stage, velocity and density logs are first reconstructed through an inversion scheme that estimates moduli and densities of the rock constituents (Chaveste, 2003B). The technique for well log reconstruction and forward modeling involves estimations, from well log data and from volume fractions, of the densities, bulk moduli, and shear moduli of the constituent lithologies and fluids. These moduli and densities are iteratively estimated by comparing (using effective media theory and Gassmann's and weighted average density equations) the reconstructed logs to the real logs. The reconstruction process is iterative and the results dependent upon log quality. The reconstruction technique assumes that the elastic moduli and densities of the constituents do not change over the interval being evaluated, and that the change of the frame's bulk modulus due to compaction can be accommodated by slowly varying (low frequency) P- and S-wave velocity functions. The final moduli and densities of the rock constituents are those that result in the minimum differences from the real and reconstructed logs. The effective matrix and fluid moduli of heterogeneous rocks are estimated with effective media theory through the use of the rock's volume fractions.

Once densities and moduli of constituents have been determined through minimization of the differences between real and reconstructed logs, petrophysical properties (phi, Vsh and Sw) can be modified and logs (Vp, Vs and Rho) reconstructed as if they had been acquired under the new (modified) condition.

Elastic parameters such as LMR™ values are then computed and evaluated for different reservoir conditions. This allows verification, at well log resolution, of the sensitivity of these parameters to changes in the petrophysical property under review in the reservoir. These same parameters will also be estimated at seismic resolution, via quantitative three-term AVO analysis from synthetic and from recorded seismic data.

Seismic modeling is the third stage. To evaluate sensitivity at seismic resolution, the reconstructed logs (Vp, Vs and density) are used to create pre-stack synthetic gathers of the same bandwidth and offset distribution as the real data. Rock properties are computed from the pre-stack synthetic gathers with the same three-term AVO algorithms as those to be used with the real data. There are two important reasons a three-term AVO solution is particularly valuable. Firstly, one usually wishes to model three petrophysical properties: porosity, lithology (shale volume) and water saturation. It is not possible to solve for the three of them uniquely with only two equations; a three-term solution is needed to solve three unknowns. Secondly, the third term is density-reflectivity, and this is desirable because it is via density that one can estimate saturation levels. Density varies linearly with water saturation, whereas P-velocity response is more like an on/off switch: Vp drops sharply upon the introduction of a small amount of gas and then remains fairly constant. That is, Vp is fairly insensitive and 'sees' water saturation levels from 0 to 85% as the same. The third term, density, can provide the needed discrimination.

In fact, in the particular case study discussed, P-wave sensitivity is large when going from fully water saturated formation (Sw=1) to approximately 88% water saturation. Lower water saturations result in only a slight increase in P-wave velocity. Notice, also that P-wave velocity is ambiguous, that is: different water saturations result in the same P-wave velocity.

Although density is a necessary property when water saturation is a property of interest, it should be noted that density alone is not a measure of Sw, as it changes also with other petrophysical properties. For example, pay sands may have the same density as non-pay sands when non-pay sands are more porous.

Three-term AVO Inversion

Zoeppritz's equations relate reflection coefficients as a function of angle of incidence to the rock properties that caused the amplitude variations: the contrast in P-wave velocity, S-wave velocity, and density across a reflecting interface. These properties determine the pre-stack seismic amplitude response; the inverse problem is to reveal rock properties by examining amplitude behavior.

Either the exact Zoeppritz equations or some linear form such as that of Aki & Richards (1980) can be used to model calculated reflection amplitudes $R(\theta)$ for given rock properties. Aki & Richards' three term equation is rarely inverted for, because for conventional seismic acquisition geometries and noise levels, the equation is ill-conditioned and tends to be unstable: a small amount of noise results in large parameter deviations.

Constraints can be used to reduce the large uncertainty introduced by the third variable. One way to do this is with hard constraints: fix the third variable in terms of a linear combination of the other two. For instance, Smith & Gidlow (1987) use the Gardner (1974) velocity-density relationship to constrain the solution.

Rather than using hard constraints, soft constraints from local well control or from known rock physics relationships can be brought into the three parameter AVO inversion to help stabilize the solution. Because seismic data are noisy and finite, many models will fit the data, but clearly some models are more probable than others. The approach followed in this paper is to perform the three-term AVO inversion following the Bayesian methodology outlined by Downton and Lines (2001). Bayes' theorem defines a rule for refining a hypothesis by factoring in additional evidence and background information, and leads to a number representing the probability that the hypothesis is true. Bayes' theorem provides a theoretical framework to make probabilistic estimates of the unknown parameters from uncertain data and *a priori* information. Observed empirical relations linking Vp, Vs, and density may be incorporated to fix the third variable in terms of linear combination of the other two. This knowledge is cast in a statistical form, a parameter covariance matrix using probabilistic constraints.

Using Bayes' theorem, the Likelihood function is multiplied by the prior probability function. The most likely solution is the one with the highest probability. The optimal solution may be found analytically resulting in a weakly non-linear equation which is solved iteratively for velocity and density reflectivity. Constraints are based on local well control, honor known rock physical relationships, and are weighted based on the needs of the data.

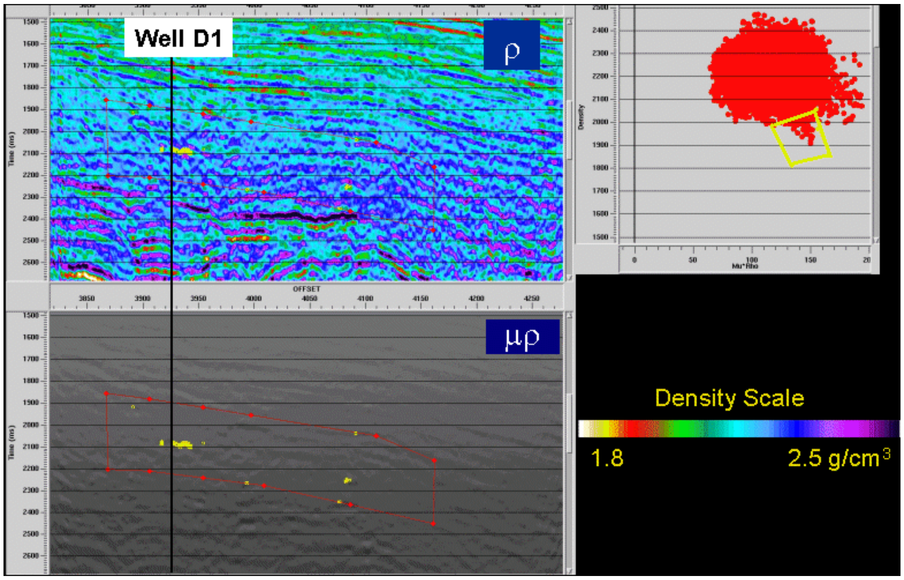

Figure 1: The density obtained from the seismic data is cross-plotted against MuRho. At the producing sand, density is anomalously low, as expected from analysis at well log resolution.

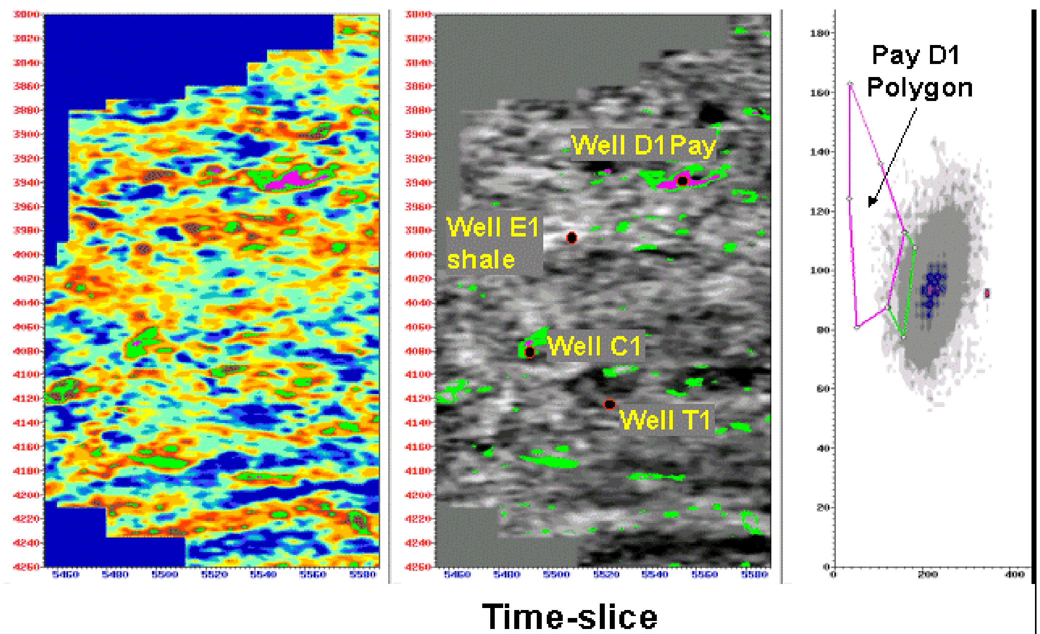

Figure 2: Time-slice view of the density cube. Data values within the well-calibrated pay polygon criteria are highlighted in pink.

Data Example: Density Extraction and Water Saturation Estimation

As an example of rock properties evaluation at seismic resolution, the sensitivity of seismically-derived LMR values to water saturation is evaluated. Petrophysical analysis, well log modeling, seismic modeling, and three-term AVO analysis of recorded data was undertaken as described above. The survey had four wells, two of which had a productive interval. Analysis in P- and S-impedance domains does not show much separation between productive and non-productive sands. Two important observations when data are analyzed in Density - MuRho cross-plot space are: 1) lowest density corresponds to the productive interval of one of the wells, and, 2) the fact that the other productive well does not show low density indicates that there is another property causing its density to be higher. Further analysis showed that this pay sand was shalier than the pay sand of the first well, giving higher density.

It is noteworthy, then, that lowest density does not *necessarily* indicate pay, but is an attribute that further reduces uncertainty.

The seismically-derived density was also cross-plotted against MuRho. At the producing sand, density is anomalously low, as expected from analysis at well log resolution. When density is cross-plotted against MuRho for the seismic line at the shalier well location, the density is *not* anomalously low, as expected from the rock properties analysis done at well log resolution.

The approach to density extraction from seismic data is validated. As well, the example illustrates that pay does not need to have the lowest density. Another important observation is that “best” reservoirs, as far as sand quality and fluid type, will, under normal conditions, have the lowest density.

Although density extraction from seismic appeared successful, it was observed that density was not an unambiguous indicator of pay. For this reason, LambdaRho™ - MuRho in cross-plot space was also evaluated. Here pay sand is separated from wet sands and, for this reason, analysis in this additional domain was considered to be valuable. Polygons were designed for the real data based on well information (Figure 1). Using the well-calibrated polygon, known reservoir conditions at well locations validated the analysis. This served to increase confidence in prospective locations (Figure 2).

Conclusions

This paper shows a case history where the predicted density from a three-term AVO inversion matched the well control. Due to the complexity of the resevoir, density by itself is not a unique indicator of commerical hydrocarbons. However, by using all three reflectivity attributes generated by the AVO inversion, the reservoir and hydrocarbons could be adequately described. Important in developing this reservoir description is the development of a linkage between the rock and fluid properties and the elastic properties estimated from the seismic, which is done by well log modeling.

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