Rock Physics Diagnostic in a Sand/Shale Sequence

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Summary

Geophysics and inversion of seismic data has improved considerably over the last decade. So much so that elastic inversion is fast becoming a commodity data product that oil companies understand and use for risk reduction. Many examples have been shown where the elastic impedance is used to estimate porosity, for example using a statistical regression on well data.

In this paper we will review the use of Rock Physics Diagnostics applied to log data that illustrates a relational model between porosity, clay and saturation. We use these relations to estimate porosity from elastic impedance attributes. Using statistical fits may work locally around the property values experienced by a well for example but away from the well you need to employ some systematic approach to improve the confidence and reduce the risk associated with such estimations. Such a systematic approach is Rock Physics Diagnostics and we believe that this methodology is essential for extracting rock properties from seismic data.

Introduction

The main task of this case study was to identify productive sands from seismic away from well control. It was assumed that the sedimentary environment away from the well was the same as at the well. The well data (onshore North America) indicate the presence of blocky oil sand and down-fining cycle below (Figure 1).

Data Analysis

The apparent velocity-porosity trend (Figure 2) is complicated and hardly predictive. In particular the Vp and Vs versus porosity trends appear to be almost flat. Therefore fitting a straight line through the data will not be useful. The task was to find an explanation and quantitative model that would allow for prediction of seismic properties away from the well.

The first step in this process was to create a series of cross-plots showing interdependence among the various rock properties. In Figure 3, we show total porosity, water saturation, acoustic impedance, and Poisson's ratio all plotted versus the natural gamma ray intensity (usually proportional to Vclay). The data separates neatly into sand and shale clusters. Note that the trend for porosity and impedance versus gamma is non-monotonic. In fact there is a clear inflection point occurring at about gamma intensity of 70 to 80. This suggests a particular rock physics model where porosity in the sand is dropping by addition of fine shale or clay particles into the original pore space. This bimodal mixing of sand and shale particles is illustrated in Figure 4.

The next step was to select a quantitative model that describes the velocity behavior as both porosity and Vclay (or Vshale) change. One such model is a simple empirical relationship originally proposed by Raymer, et al, 1980. This model can be expressed as

$$Vp_{rock} = (1 - \phi)^2\, Vp_{solid} + \phi\, Vp_{fluid}$$

Where Vprock is the compressional velocity of the bulk rock, Vpsolid is the compressional velocity of the average solid mineral phase (in this case a mix of quartz and clay), and Vpfluid is the compressional velocity in the pore fluid. Shear wave velocity was computed using a simple linear relationship called the Castagna "mudrock" equation (Castagna, et al, 1985). It can be expressed as

$$Vshear = 0.862\, Vp - 1.172$$

Where Vp and Vs are in km/sec.

In order to test this model, we first converted the entire well log to a "common fluid denominator" by performing a P-wave only fluid substitution (Mavko, et al.,1995) to 100% Sw for all depths. The log P-wave impedance (Ip) data was then plotted versus total porosity (Figure 5). The Raymer model predicted Ip is shown as a series of lines, each representing different amounts of clay. The data points are color coded by clay volume and appear to correspond closely to the model prediction. This model explains why the velocity versus porosity trend appears to be almost flat in Figure 1. We now see that as porosity goes down, Vclay goes up and since the seismic velocity of clay is less than quartz, there are two counteracting effects on rock velocity.

The simple Mudrock Vs model gave very good agreement to measured Vshear from the dipole sonic log (Figure 6). Poisson's ratio versus porosity is interesting. For sand when we reduce the porosity, we usually expect the Poisson's ratio to decrease with decreasing porosity. Here we see PR increasing with decreasing porosity. This is the effect of the clay particles reducing the porosity as we discussed earlier.

With a valid rock physics model established, the next step was to determine how to perturb porosity and lithology conditions. One big question was "What would the seismic reflectivity look like if the well was shaled out?" Figure 7 shows that if porosity decreases, Vclay increases and water saturation approaches 100%. We therefore replaced the porosity and Vclay in the pay zone with values typical of the underlying shale, with Sw equal to 100%. The model was used to predict the resulting Vp and Vs.

Discussion

The results of rock physics modeling allowed us to identify the pay sand zones from the seismic data. Figure 8 shows a Poisson's Ratio volume computed by acoustic and elastic impedance inversion. The reservoir was delineated by applying cut-offs for Poisson's Ratio and P-wave impedance.

Within this pay sand we then applied the rock physics model again to predict porosity. The analysis shows that porosity ranges from about 15% to 25% in the direction indicated by the arrow in Figure 9.

Conclusion

Using well log data as input we have identified simple empirical models to describe the Vp and Vs behavior of the pay sands and surrounding shales. This model was then used to transform acoustic impedance and elastic impedance volumes into a pay sand porosity volume.

References

Raymer, L.L., Hunt, E.R., Gardner, J.S., An improved sonic transit time-to-porosity transform, SPWLA, 21st Ann. Logg. Symp., July 1980.

Castagna, J.P., Batzle, M.L., and Eastwood, R.L., 1985, Relationships between compressional-wave and shear-wave velocities in clastic silicate rocks, Geophysics, 50, 571-581.

Mavko, G., Chan, C., and Mukerji, T., 1995, Fluid Substitution: estimating changes in Vp without knowing Vs, Geophysics, 60, 1750-1755

[1]Rock Solid Images, 2600 S. Gessner, #650, Houston, TX 77063, USA,

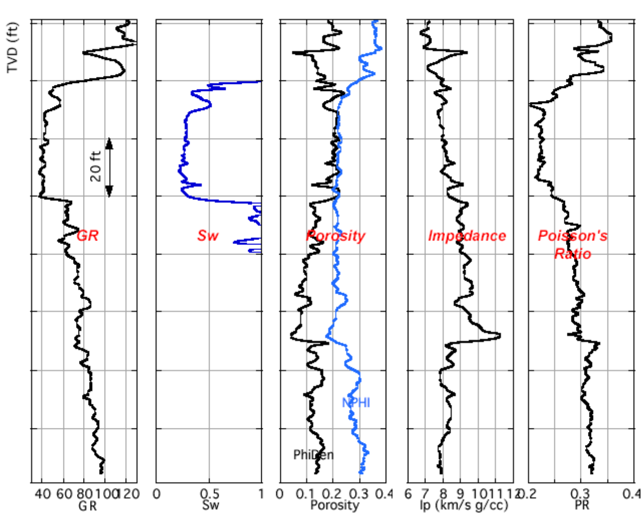

Figure 1: The well data indicate the presence of blocky oil sand and down-fining cycle below.

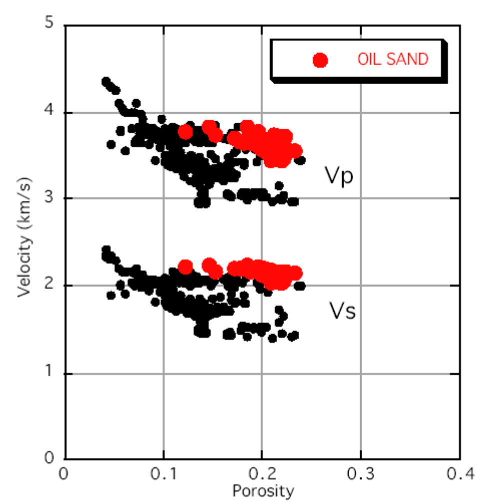

Figure 2: The p-wave velocity versus porosity trend for the sands is essentially flat and not useful for prediction.

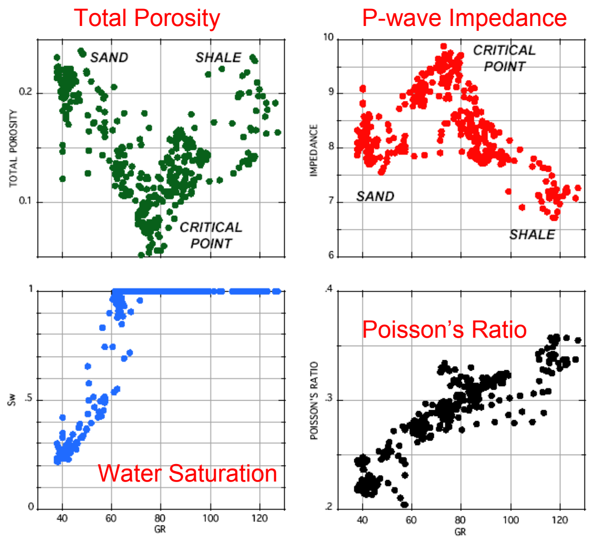

Figure 3: Diagnostic crossplots of well-log data.

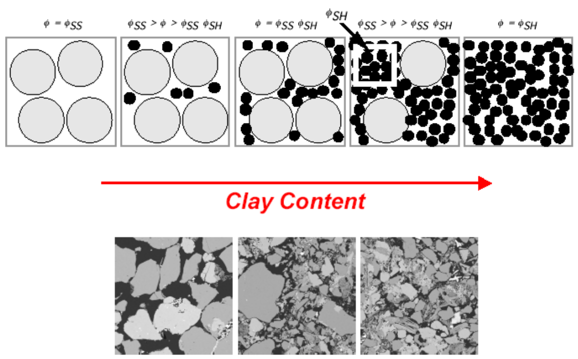

Figure 4: Diagram of bi-modal sand-shale mixing.

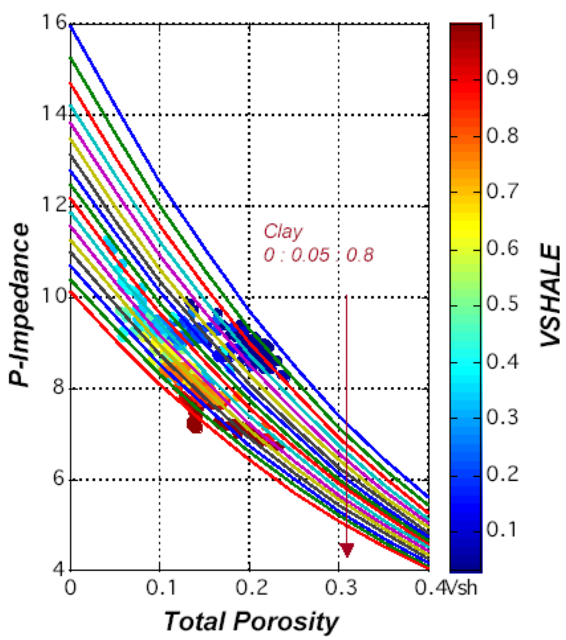

Figure 5: Predicted and measured P-wave impedance.

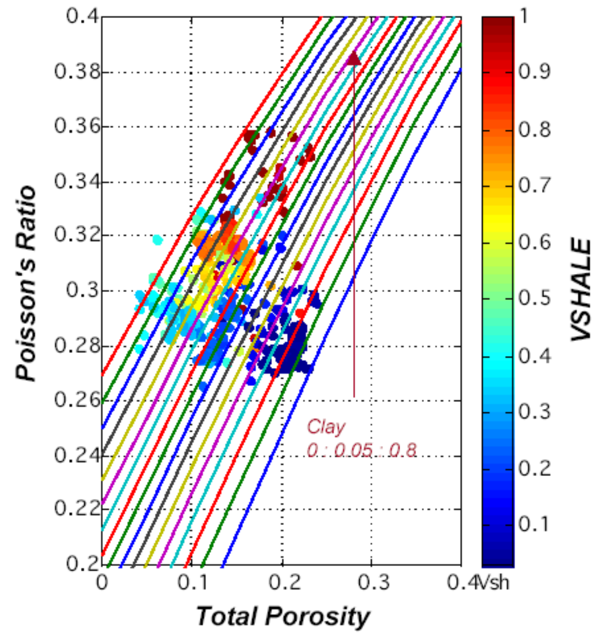

Figure 6: Predicted and measured Poisson's Ratio.

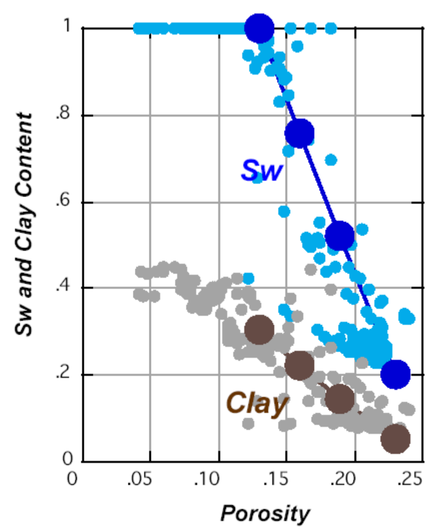

Figure 7: Relationship between water saturation, Vclay, and Total Porosity for pay sand interval.

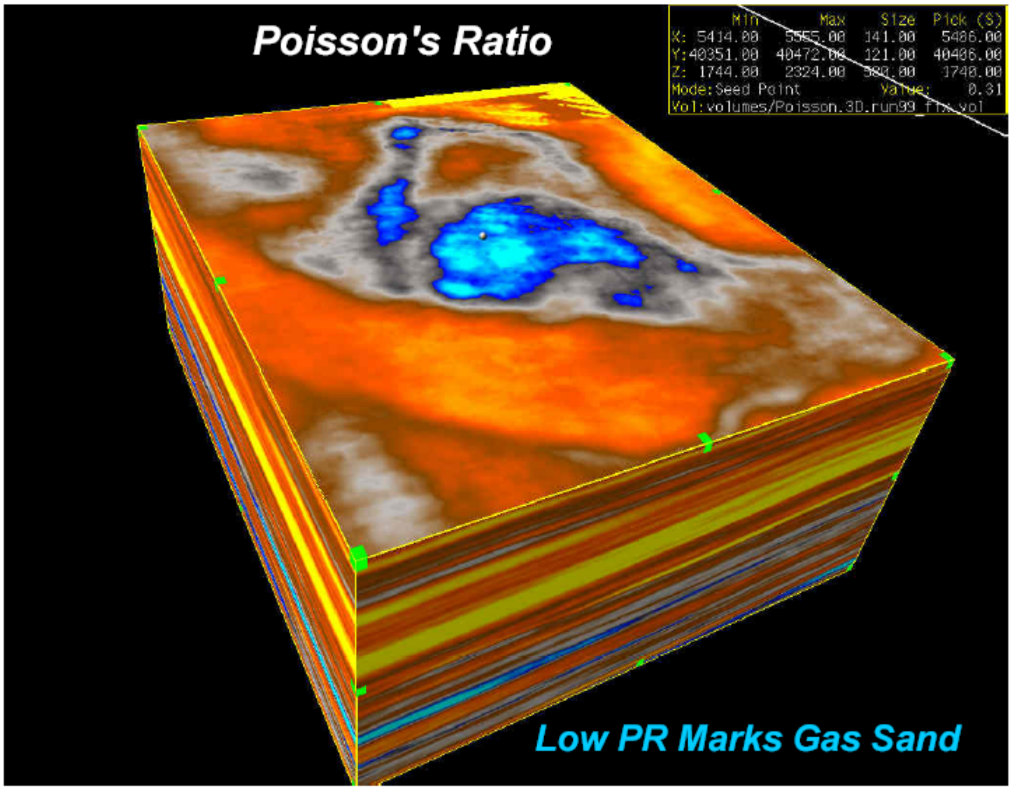

Figure 8: Low Poisson's ratio is used to identify pay sands.

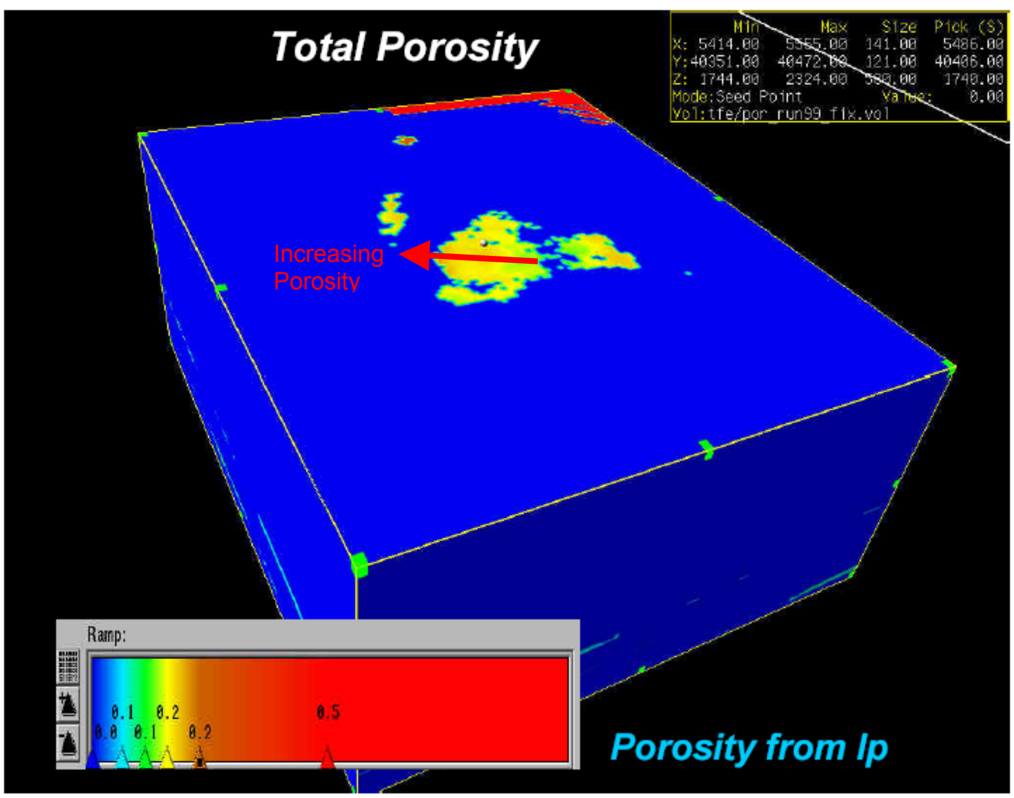

Figure 9: Porosity in pay sands from acoustic impedance using the rock physics.