

Rock physics evaluation of deepwater reservoirs, West Africa

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Summary

In this paper we discuss a workflow for rock physics evaluation of a deepwater turbidite offshore Angola. This includes data conditioning, anisotropy correction and fluid substitution with special focus on thinly bedded sand-shale sequences, in which laminations are often if not always ignored. We also discuss a stochastic rock physics workflow and tools we have implemented for facies classification to translate inverted acoustic impedance and V_p/V_s volumes into probabilities of occurrence of shales, hydrocarbon sands, wet sands, gravels and silt. This workflow has proven critical in our reservoir characterization efforts, both for exploration and development projects worldwide.

Introduction

Quantitative seismic interpretation plays a major role in reservoir characterization for unlocking the potential of hydrocarbon accumulations, and rock physics sits at the heart of that. A thorough rock physics assessment to understand the elastic behavior of any given reservoir is paramount for many, if not all, seismic reservoir characterization activities. However, for any rock physics diagnostics and interpretation work, some basic steps are required to achieve meaningful results, such as well log data conditioning, correction for anisotropy if needed as well as making proper assumptions about the effective medium. We will show how all that is integrated in a stochastic rock physics workflow for reservoir facies classification.

Seismic inversion on the other hand is a viable tool in transforming seismic reflection data into quantitative properties for reservoir characterization. Therefore, the ability to project these volumes into probabilities of rock types 'seismic facies' allows for effective communication with geomodellers, hence more efficient workflows. In this paper we will discuss the above integrated workflow which includes data mining of well logs (QC, editing, corrections and calculations), tuning of rock physics models, mechanized generation of relevant data displays in order to understand rock behaviors and finally a stochastic rock physics workflow to define classification templates for Bayesian classification of inverted seismic data.

We will show an example from a deepwater turbidite offshore Angola (see Nasser et al. 2010, 2011 & 2012 for more details) where a series of confined channel systems have been interpreted on seismic data and the impact which the

workflow described above has made on the characterization of these deepwater reservoirs.

Data QC and anisotropy correction

Sonic logs measured along deviated wells, and in the most general case at an arbitrary angle with regard to the dips of the stratigraphy, require correction for vertical velocities. Moreover, very often when dealing with a shear sonic data, it is not known whether it corresponds to a slow or a fast arrival and in turn, vertical or horizontal polarization of the shear wave. In most cases what is obtained is a mix of the two (cross-dipole mode logging). This makes it very difficult to properly correct the measurement for anisotropy since it requires the type of shear propagation intended to be corrected.

The anisotropic correction assumes a simple VTI medium, using Thomsen's approximation (Thomsen, 1986) for weak anisotropy. The coefficients are estimated using VSP information, looking at the difference in compaction trends among neighboring wells with different inclinations, and comparing multiple side-track legs of a single well at different angles in addition to the central vertical hole.

Fluid substitution and shale delamination

Gassmann's equation (Gassmann, 1951) is widely used to relate the saturated bulk modulus of the rock to its porous frame properties and the properties of the pore-filling fluids. However, it assumes a homogeneous mineral modulus and statistical isotropy of the pore space but free of assumptions about the pore geometry. Most importantly, it is valid only at sufficiently low frequencies such that the induced pore pressures are equilibrated throughout the pore space. Violating any of these basic assumptions will lead to errors in fluid substitution as well as rock physics models, especially for inter-bedded sands and shales in deepwater turbidites if such laminations are not properly handled. Dejtrakulwong and Mavko (2011) proposed a new method for doing that using the Thomas-Stieber (1975) model to detect laminations and then downscale for the sand and shale end-members' properties, apply Gassmann's equation to sand layers only, and then upscale the layers back using the Bakus average (Katahara, 2004; Skelt, 2004). This is an elegant way to remove the influence of 'clay minerals' on the calculation of the solid and dry frames giving a stable fluid substitution. This approach can be used for fluid substitution when sub-resolution impermeable layers lie within the interval.

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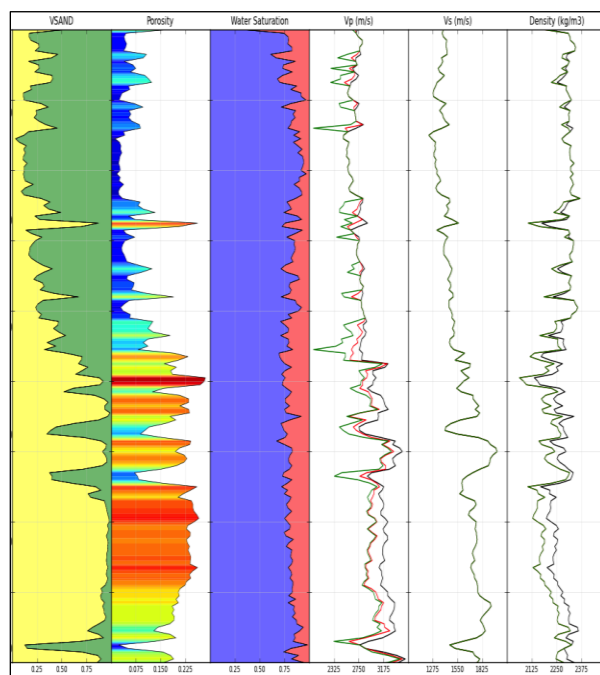


Figure 1. Comparison between Gassmann fluid substitution results from brine to oil with and without shale delamination (black: insitu data (brine), red: oil with shale delamination, green: oil without shale delamination)

However, the method we used here is not only equivalent but also much simpler, following Katahara, 2004; Skelt, 2004, which starts by delaminating the shales using an isostrain average (Reuss bound), compute the bulk modulus of the dry frame, then the saturated bulk modulus using the new fluid mix for the sands only and finally laminate the rock back together (saturated sands and shales) also using Reuss' average. Figure (1) shows the results of this workflow by comparing the fluid substitution results with and without shale delamination. The effects are seen on V_p only (Black: insitu data, Green: without shale delamination and Red: with shale delamination). The main reason for the erroneous fluid response (green curve) without shale delamination is that shales 'clay minerals' in this case are considered part of the solid and dry frame, hence, making it weaker and as a result exaggerates the fluid response, especially at low porosities. Delamination corrects for that by only using a solid frame that holds the effective porosity for fluid substitution. This new method is also designed to take into account laminar shales, dispersed shales and structural shales if they all can be petrophysically separated on well logs using the Thomas-Stieber model.

Rock physics modeling and estimation of silt volume

The turbidite sequences encountered in this area are mostly dominated by laminations of sandstones and shales with individual layer thicknesses below the resolution of the sonic logging tool. For this reason, we have assumed a lamination/de-lamination process for both fluid substitution and rock physics modeling, implying that we are dealing with end members in the lamination (sand/shale), hence, any porosity will be associated with the clean sand layers.

The rock physics modeling is composed of two main elements, one describing the reservoir rocks (sand) and another describing the non-reservoir rocks (shale & silt). These components are assembled together using Gassman's equation to mix the porous rock and the fluid, followed by a Reuss average to laminate the saturated sands and shale. For this specific case, empirical trends are estimated to capture the behavior of shales (compaction trends most likely due to de-watering), which are rather simple linear relationships as a function of burial depth. The simplicity of this compaction trend is by no means dictated by any of our tools or workflows; however, it seems sufficient to capture the general shale trend in our borehole data. Empirical models are also used to explain the behavior of porous rocks, describing the incompressibility and shear moduli of the rock frame (dry moduli). In this case we scan different template models and optimize their coefficients and at the end select the one that best represents the data.

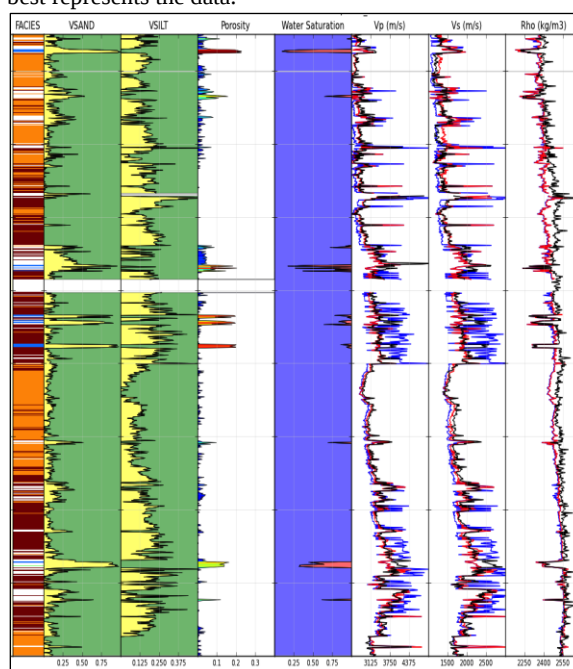


Figure 2. Comparison between the rock physics model with (red) and without (blue) the predicted silt volume (track 3). Black curves are the insitu well logs.

Fluid substitution is performed using Gassmann's equation, however, one must pay special attention to the lamination/de-lamination step discussed earlier; otherwise, the underlying effective media is not accurately represented and will lead to erroneous results. Until recently our models included only

rock physics approach to establish a Bayesian classification scheme of inverted P-impedance (I_p) and V_p/V_s in order to estimate probability volumes of different 'seismic facies' for shale, sandstone (brine or hydrocarbon filled), gravel (irrespective of filling fluid), and silt, following a scheme

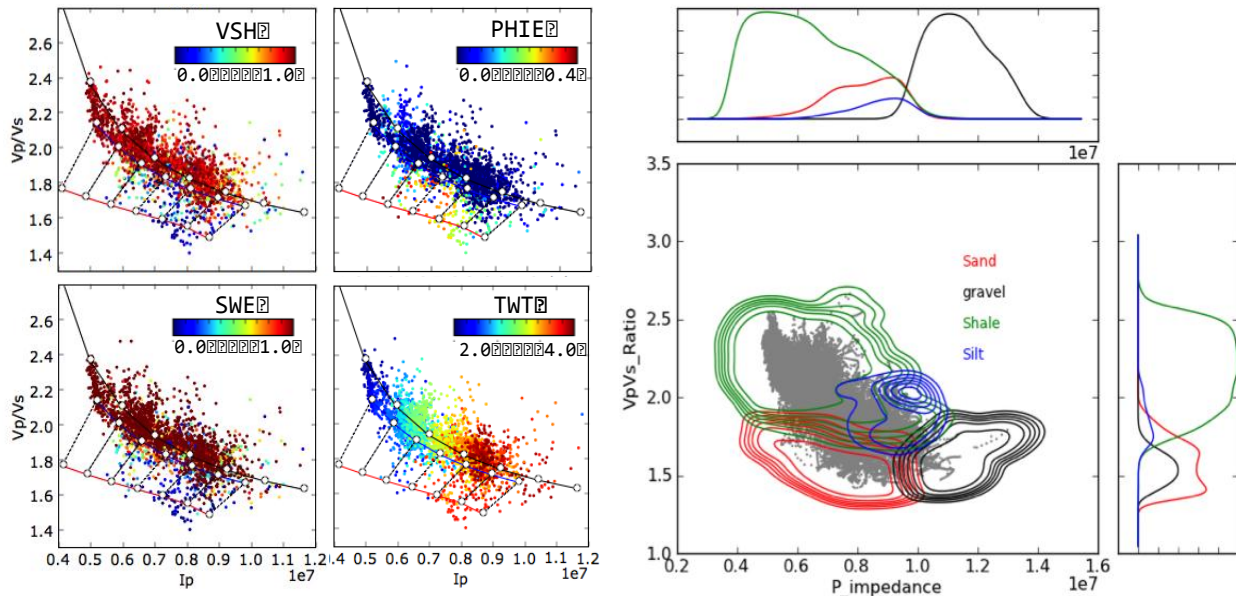


Figure 3. Facies classification in different domains using log data. This is used for transforming the inverted volumes into probabilities of sandstones, gravels, shales and silts.

sandstones, gravel and shales. However, the presence of siltstone clearly observed in recent wells has complicated our AVA interpretation and hence, rock physics predictions needed updating. Therefore, the volume of silt was estimated starting from the existing rock physics model and comparing its response with the measured, hence explaining such difference by the presence of silt (Figure 2). The scheme was posed as an optimization problem where estimates at every location are made in depth and for every well the optimal silt volume in order to simultaneously minimize the differences between measured and modeled V_p , V_s and bulk density. In order to minimize bias, the initial regional model for shale compaction was established using only those wells where we suspected the silt volume to be very small. Estimating the silt volume for the different wells in this area has significantly improved our understanding of the subsurface and hence our prediction of the hydrocarbon accumulations in the different sands.

Stochastic rock physics and Bayesian classification

When enough accumulated understanding of the elastic behavior of the rocks is built into models to explain extreme or yet-to-be-encountered scenarios, we follow a stochastic

similar to the one explained in Escobar et. al (2010); and using the classification templates shown in Figure 3. The left of Figure 3 shows four cross-plots of V_p/V_s against P-impedance for a few wells colored with shale volume, porosity, saturation and the two-way travel time. These plots highlight the shales (high V_p/V_s) and the sands of lower V_p/V_s and much higher porosity. Gravels on the other hand are of a similar V_p/V_s as the sandstones except they have much higher impedance. On the other hand, the silt behaves elastically in between sands and shales but has a distinctly low porosity (non-reservoir). Therefore, integrating sonic and density logs with petrophysical logs can provide an excellent facies classification scheme as seen on the right hand side of Figure 3, which is later integrated with the inversion volumes.

The elastic seismic inversion was carried out using a proprietary deterministic geostatistical scheme (Cherrett et al. 2011), however the details of this work are beyond the scope of this paper and will be published later on as a follow-up paper. For the sake of completeness, in Figure 4 we show extractions for one of the reservoir units showing the V_p/V_s in Figure 4A and the probability of oil filled sands in Figure 4B. In these two maps it is clear that the areas of V_p/V_s indicating

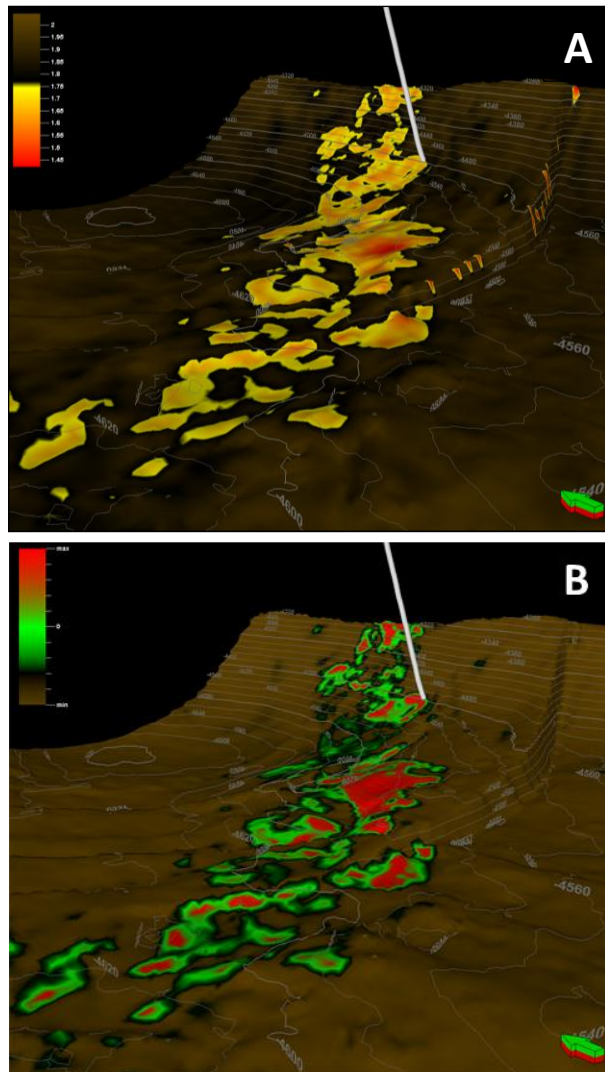


Figure 4. Maps of V_p/V_s (A) and probability of oil (B) for one of the deepwater reservoir units.

sand (yellow and red) and the probability of oil (green and red) are similar but not identical. This indicates that some sandstones are either brine filled (no green where V_p/V_s is yellow) or oil filled (green and red corresponding to a low V_p/V_s highlighted in yellow). Similar maps were generated for multiple reservoir levels and showed excellent agreement with the well penetrations. Therefore, this integrated rock physics and inversion workflow has improved our prediction of hydrocarbon accumulations and as a result has led to an optimized well drilling strategy.

Conclusions

We have shown an integrated stochastic rock physics and deterministic geostatistical seismic inversion workflow for characterizing deepwater reservoirs offshore Angola and the following are the critical components of this workflow:

- Data QC and conditioning, some of which are correcting for well deviation and anisotropy.
- Fluid substitution in laminated sands and shales. This is a two-step process requiring shale delamination to accurately compute dry and saturated bulk moduli for the sands only, and then mix the delaminated shales and the saturated sands using the Reuss average.
- Estimation of silt volume in addition to sand, gravel and shale volumes is critical for better interpretation of seismic data.
- Integrating stochastic rock physics and seismic inversion results for facies classification leads to a better prediction of hydrocarbon accumulations.

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EDITED REFERENCES

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