Integrating rock physics and full elastic modeling for reservoir characterization

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Summary

Rock physics establishes the link between reservoir properties, such as porosity, lithology, fluid type and the seismic response. It is a tool by which a range of subsurface scenarios can be built to estimate the seismic response beyond what is observed at the well location. In this study we show how rock physics and full elastic 2D seismic forward modeling can be integrated to produce realistic subsurface images, which can be used in conjunction with 3D seismic interpretation.

We demonstrate our integrated rock physics and full elastic 2D seismic forward modeling technique for a turbidite sandstone offshore Angola, where sand and shale properties vary with depth due to local differences in depositional character. This work complements a 2010 SEG abstract by Nasser focused on the rock physics model in which effects of pore fluid, lithology and depth on AVO signatures were investigated.

Introduction

Data from several wells from deepwater offshore Angola was used for this study. Target reservoirs in the area of interest are deposited in middle to lower slope settings, following the trend of many of the deepwater reservoirs in this area, which vary in style and consist of strongly to moderately confined, channel systems that are typically sinuous, leveed channel systems and local ponded to distributive systems. Sand types vary from high concentration turbidites (fine grain sands) to traction of coarse grain material (gravel) with varying shale content. Moreover, the observed AVO classes are dependent on the sand type (fine grain vs. gravel), fluid content and depth. Several wells have already been drilled in this area, which were used to build the rock physics model for the block and to predict the AVO response as a function of depth of the target sands. Sonic and density logs as well as the full suite of petrophysical logs such GR, porosity, Vshale and saturation in each well were used. In addition to that two walkaway VSP lines acquired over one of the wells to estimate the anisotropy parameters and to calibrate the AVO response observed on the seismic data were also used. Several attempts were made to estimate the anisotropy parameters from walkaway VSP data acquired over a few wells in the block from which a wide-range of values were found. However, the following are the most up-to-date values: epsilon = 0.16, delta = 0.12 & gamma = 0.1 which are used in this study. Seismic data on the other hand was originally migrated with isotropic velocity model and is considered of reasonable quality on which robust fluid related anomalies can be observed and interpreted. The seismic data is being reprocessed with a Tilted Transverse Isotropy (TTI) velocity model to account for anisotropy. The area of interest for this study is limited to two wells in which one of them is deviated with two sidetracks, which have a complete set of logs and core data.

The oil industry has a long history of trying to use full wave-form 2-way wave-equation modeling for a wide variety of interpretation issues (Stoughton, et. al., 2001; House, et. al. 2002; Margrave et.al., 2004; Chopra 2005): acquisition design (almost exclusively acoustic), subsalt, 4D, etc. However application of full elastic 2D and 3D modeling to amplitude and AVO interpretation is not well published.

An elastic model was constructed by combining data from surface seismic data, well data, interpreted information, and a Rock Physics Model (RPM) that explains the AVO characteristics of the target reservoirs. The model was used to validate the rock physics model with surface seismic, plan acquisition parameters to optimize for amplitude interpretation, and to predict reservoir characteristics away from existing well bores. The RPM was presented by Nasser (2010) so will not be discussed in detail here. The reservoir is a stratigraphic trap in a compaction driven system complicated by salt structures and faulting. Both surface seismic and VSP data show obvious effects for strong seismic velocity anisotropy (at least VTI, but probably TTI). Precise and accurate amplitude preserving preprocessing and depth migration are critical to getting the maximum from the seismic data.

Rock physics model

We propose a typical workflow of three steps to predict the elastic response of thin-bedded sand shale sequences with varying fluid types and saturations.

In step 1 we establish the petrophysical trends at varying depths for the end-member sands, gravels and shales using brine filled logs (Vp, Vs and density). For the sands/gravels we establish a relationship between Vp and density as well as Vp and Vs, which indirectly accounts of the effects of the vertical effective stress on the sands porosity and stiffness due to compaction. However, for the shales we establish the following relationships (Vp as a function of depth; Vs and density as a function of Vp). In this case we assume that the shale is completely impermeable to hydrocarbons and only saturated with brine trapped during deposition. It is reasonable to assume that the porosity of the thin-bedded shales at a given depth will be fairly constant (Avseth et al. 2006)

In step 2 we apply Gassmann's theory and perform fluid substitution on the wet clean sands and gravels to estimate their elastic properties assuming uniform but varying fluid saturations. Seismic fluid sensitivity is determined by combination of porosity and pore stiffness. A softer rock will have a larger sensitivity to fluids than a stiffer rock at the same porosity (Avseth et al. 2006). Gassmann's relations reliably describe these effects via the following relationship:

$$\frac{K_{sat}}{K_{\min}-K_{sat}}=\frac{K_{dry}}{K_{\min}-K_{dry}}+\frac{K_{fluid}}{\varphi\left(K_{\min}-K_{fluid}\right)}$$

Nasser 2010 rewrote the above equation, dropping out the K_{dry} terms, which allows going between multiple fluid saturations of the rock without computing the K_{dry} term; see equation (3) in Nasser 2010 for the final relationship.

In step 3 we apply Backus average effective medium theory (e.g., Gelinsky and Shapiro, 1997; Mavko et al., 1998) to estimate the effective, upscaled anisotropic properties of the interbedded shale and sand sequences using various net-to-gross values, ranging between 0 and 1. This averaging techniques approximates a stack of alternating thin layers of two isotropic media as one effective anisotropic medium, which is characterized by five independent elastic moduli described in Avseth et al. 2006.

Analysis of well data

The three-step methodology discussed above was applied on several of the Block's well data, which later used to predict the seismic response away from the wells. This was following an analysis of the data using both the Voigt-Reuss and modified Hashin-Shtrikman upper and lower bounds to assess the elastic moduli of the clean sands from seven different wells. These bounds provide a framework for understanding the acoustic properties of sediments, before deposition, after deposition and upon burial, where the various processes that give the sediments strength, effective stress, compaction, and cementing and move the sediments off the Reuss bound take place.

Figure 1 shows the bulk modulus versus porosity for several wells saturated with brine, and color-coded with depth. Notice that deeper sediments have moved off the Reuss and the modified lower H-S bounds while the shallower unconsolidated sands (blue color) are sitting right on the lower bounds. The solid lines of the bounds correspond to the deeper clean sands with a higher brine bulk modulus, while the dashed lines correspond to the shallower clean sands with a lower brine bulk modulus.

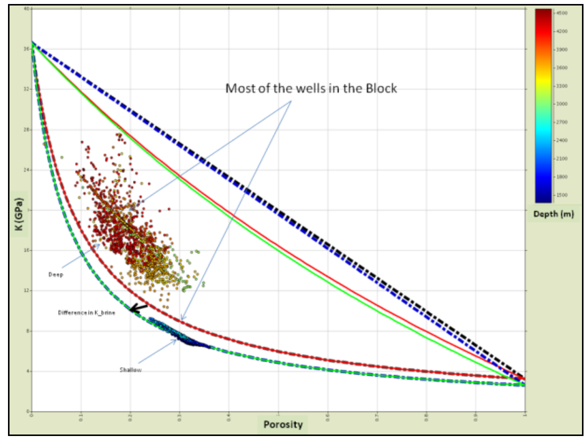

Figure 1: Bulk modulus versus porosity for brine filled sands from different wells compared with the Voigt-Reuss and the modified Hashin-Shtrikman bounds.

Figure 2 shows the application of the methodology outlined above on one of the wells, in which porosity, fluid saturations and sand volume logs were used as input to the model to compute the compressional velocity, shear velocity and density (red curves) assuming a wet sand and then compared with brine filled well data (black curves) in panel Number 2, 3 & 4. In panel 5 we compare the impedance response of the brine logs data, brine model and hydrocarbon (HC) model in black, red and green respectively.

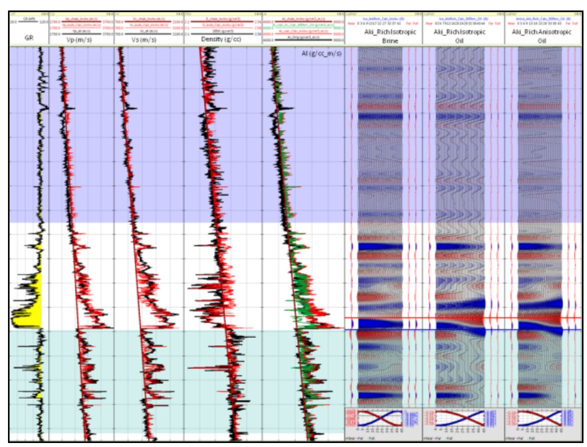

Figure 2: A match between the trend-based rock physics model (red) and the log data (black) response for Vp, Vs, Density and AI. Isotropic and anisotropic gathers were computed for both wet and Hydrocarbon sands.

The three gather panels to the right show the expected AVO response for isotropic wet sand assuming isotropic shale, isotropic HC sand assuming isotropic shale and isotropic HC sand assuming anisotropic shale respectively. For this modeling we have used the following values for Thompson's parameters to model the anisotropy effects on the AVO response. Values used are epsilon = 0.16, delta = 0.12 & gamma = 0.1 which were estimated using walk-away VSP data in the well shown in Figure 2.

2D elastic model

As a first step an interpreter located the major stratigraphic components of the reservoir zone (Figure 3). Those stratigraphic features were imbedded within a background model of shale (dark brown). The geophysicist then built the background shale elastic properties from well and seismic information for velocities, density, and velocity anisotropy parameters. The final model is composed of vertical compressional velocity (V_p), vertical shear velocity (V_s), density (ρ), and Thomsen parameters (δ and ε) (Thomsen, 1986). Reservoir properties were assigned to each of the facies in the form of Net-to-Gross (NTG), Oil Saturation (S_{oil}), and Porosity (φ), from which elastic properties were computed using the RPM described above.

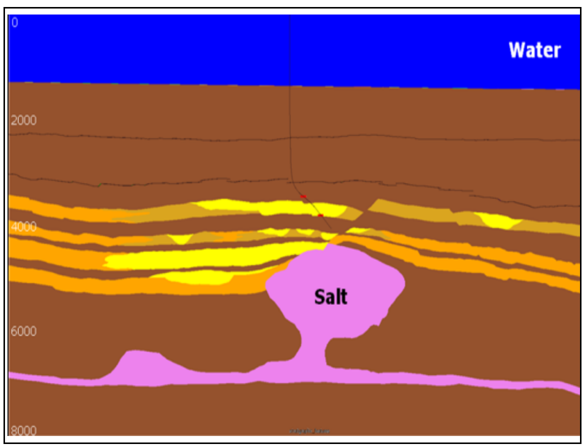

Figure 3: 2D facies model.

The Background elastic model is a critical part of the complete modeling process. It must be consistent with all information sources and yields the appropriate AVO response in the presence of reservoir sands. Calibrating the background elastic model to the RPM ensures that both required conditions are honored. The process adopted in this study used a dual calibration process as necessary: elastic properties were adjusted to fit seismic and well information then adjusted to fit the RPM. The Vp and ρ are the only two elastic parameters quantitatively measured with seismic and/or well data, thus, the first step in the modeling process was to make both consistent with the available information and the RPM. For example, the V_p model started with an isotropic depth migration velocity volume that was first calibrated with well information to approximate vertical velocity then calibrated to the RPM. Density followed a similar modeling path combining well-log data with a shale compaction model (Figure 4). The V_s model was derived from the V_p model using a constant V_s/V_p ratio of 0.58 as predicted by the RPM.

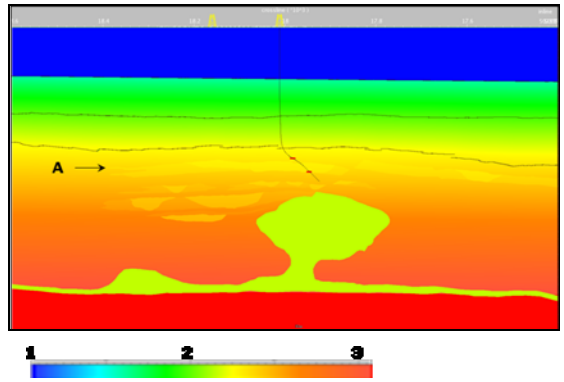

Figure 4: Density model.

The effect of anisotropy on the AVO response of the seismic and VSP data must be considered for these geologic settings. Background Thomsen parameters were derived from VSP data, and then modified to smoothly go to zero at the water-sediment interface.

Seismic simulations

Simulated 2D shots were computed with the elastic model using a 2-way, elastic finite difference algorithm (Levander, 1988; Juhlin, 1995). The sample shot shown in Figure 5 has many characteristics of a typical field shot acquired in Angola, although the shot was computed without free surface multiples. The Wave Equation Migration (WEM) image of a portion of the model using many computed shots (Figure 6) shows that the reservoir features are well imaged. The shape of reservoir features matches that of the model. Tuning effects at the edges of the channels are also evident in Figure 6. An image gather demonstrates the characteristics of the amplitude changes with offset for the same location as the shot gather in Figure 4. Phase changes with offsets are present within the zone of interest. Although not shown here, near, mid and far offset substacks reproduced the expected AVO response for the target sands.

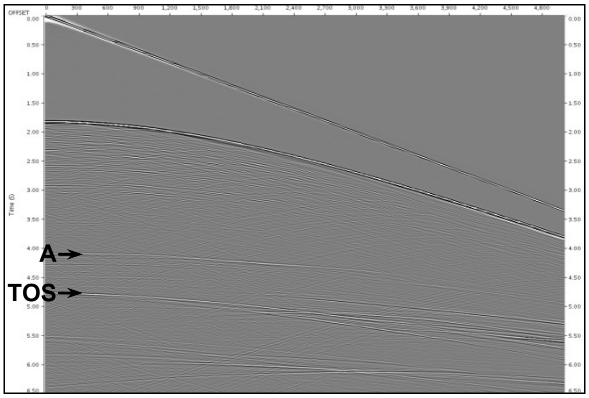

Figure 5: Example shot. Location of event "A" in Figure 4 is highlighted as well as the top of salt (TOS) reflection.

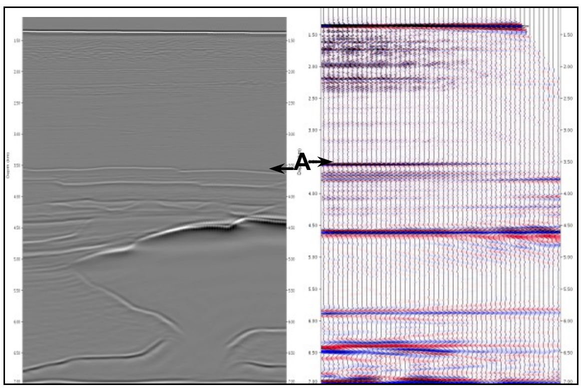

Figure 6: Left side is a VTI, WEM image of simulated shots. Right side is an image gather at the location marked by the dashed red line.

Conclusions

We have shown a method by which integrating a RPM and full elastic forward modeling algorithm have led to a more robust synthetic pre-stack seismic images which has proved to be useful in seismic interpretation.

Acknowledgements

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EDITED REFERENCES

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