

Petrophysical Seismic Inversion over an offshore carbonate field

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Abstract

The main objective of this project was to evaluate the ability to derive petrophysical properties like porosity from pre-stack seismic data in a carbonate environment. We apply a direct petrophysical inversion technique to an offshore carbonate reservoir. Starting from an initial geological model in depth and a number of carefully conditioned seismic angle stacks, we derive a detailed 3-D model of the porosity and hydrocarbon saturation matching the observed seismic data. We use a well-calibrated Petro-Elastic Model (PEM) to link the petrophysical properties to the seismic velocities. We compare inversion results obtained using the Xu-Payne and T-matrix PEMs which both account for carbonate pore geometry, lithology, porosity and fluid content but have different elastic sensitivity to fluid saturations. The inverted results provide detailed images of the spatial variations of porosity and fluid content across the reservoir interval. Predicting absolute saturation values is more difficult, as saturation estimation is strongly dependent on the choice of PEM.

Introduction

Carbonate reservoirs are notoriously heterogeneous. Seismic inversion is therefore needed to help estimate the spatial variations of rock type, porosity and fluid content between available wells. We present the results of a direct inversion of porosity and saturations from seismic pre-stack data over an offshore carbonate reservoir.

Petrophysical Seismic Inversion: Methodology

Petrophysical seismic inversion (Bornard et al., 2005), (Coléou et al., 2005), is applied on a geo-cellular model filled with rock properties in depth. The objective is to make the geomodel consistent with observed pre-stack seismic observations. The direct petrophysical inversion workflow is illustrated in Fig. 1. We start from an initial fine-scale geomodel defined from a 3-D stratigraphic grid in depth (left). Seismic forward modelling includes the computation of the elastic response (middle) in each cell of the geomodel through the Petro-Elastic Model (PEM) from stored values of porosity, rock type and saturations.

Angle-dependent reflectivity series are then calculated from the elastic properties through the Zoeppritz equation at each trace location. The resulting reflection coefficient series are converted from depth to time using the compressional velocities stored in the stratigraphic grid. Angle-dependent 3-D synthetics (right) are finally generated by wavelet convolution and compared to the observed seismic data. Perturbations of layer thickness and of selected properties of the geomodel are introduced using a simulated annealing algorithm to optimise the degree of match between the synthetic and the real angle stacks. After convergence, the final geomodel honours the observed seismic amplitudes, is consistent with the user-specified PEM and integrates inversion-based velocities that ensure coherence between the depth and time domains.

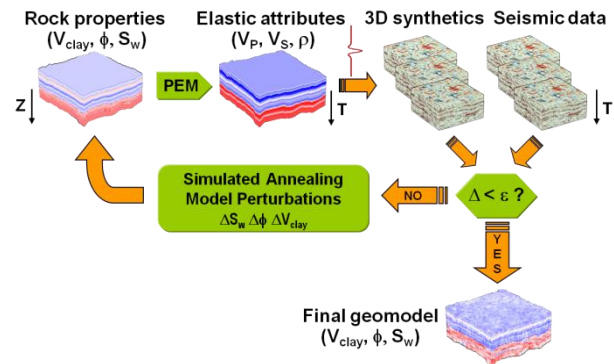


Fig. 1. Conceptual view of the petrophysical inversion workflow.

The direct petrophysical inversion is model-centred as opposed to a traditional seismic-centred inversion. It adjusts the rock properties stored in the initial geomodel to fit the observed pre-stack seismic data. By progressively relaxing the constraints and introducing more degrees of freedom, we can quantify the impact of each of the parameters and detect when the limit of resolution of the inversion is reached, that is when the solutions are sampling the null-space of the inversion and do not provide any improvement in the seismic match. The geomodel is a layered model in depth and layer thicknesses can be adjusted as part of the inversion process. The stratigraphy may be adapted to the seismic resolution by introducing more layers or coarsening the geomodel. Because the geomodel is parameterized in terms of petrophysical properties, we can easily test different reservoir hypotheses. We can for example compare a brine-case where hydrocarbons are forbidden versus a mixed fluid case where oil may be introduced.

Petrophysical Seismic Inversion: Data

On the offshore field investigated, four exploration wells have been drilled. A seismic section running through the wells from the near stack cube is displayed in Fig. 2. A simple initial model is built based on well observations and interpreted events. It consists of alternating tight zones and more porous intervals with constant values as illustrated in Fig. 2.

The seismic data consist of seven angle stacks with angles ranging from 0 to 35° of incidence angle. The seismic data were processed and preconditioned to be suitable for seismic inversion. The preconditioning steps, including anti-multiple, time misalignment correction and AVA control, were optimised and checked against their impact on inversion results. Quality indicators and statistical analysis of the residuals (difference between real data and synthetics computed from inversion results) were used to evaluate the impact of different processing steps on the quality of the seismic match, enabling optimal parameters selection. For example, applying time misalignment correction across angles leads to more Zoeppritz-compliant amplitudes and therefore to a reduction of the inversion residuals, an increase of the correlation, a reduction of the NRMS between seismic and synthetic data and an overall better quality indicator.

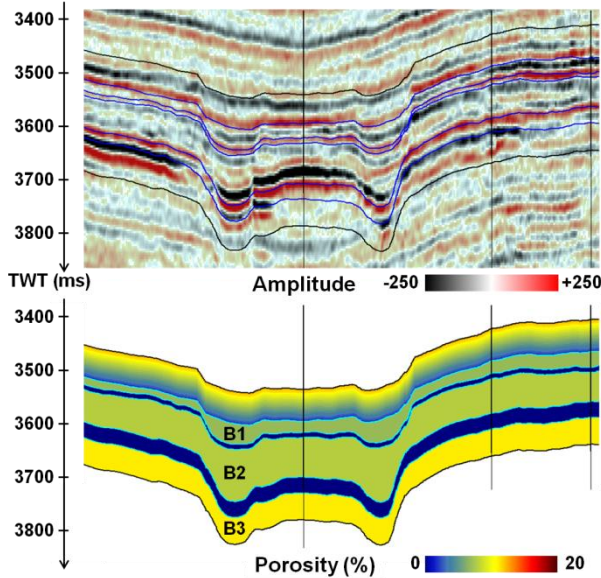


Fig. 2. Near stack seismic section (top) and initial porosity model (bottom).

Petro-Elastic Model

This step is critical. It reconciles different static measurements (cores, logs and seismic) obtained at different scales and different domains (depth and TWT). For this study we have compared the use of two different inclusion models. First we have tried an extended Xu-White model (Xu et al., 2009) which accounts for a variety of pore types. This model is based on the Kuster-Toksöz and Gassmann theories as described in Fig. 3. This

model is lightweight and relatively easy to parameterize and is well suited to obtain a satisfactory calibration at the wells.

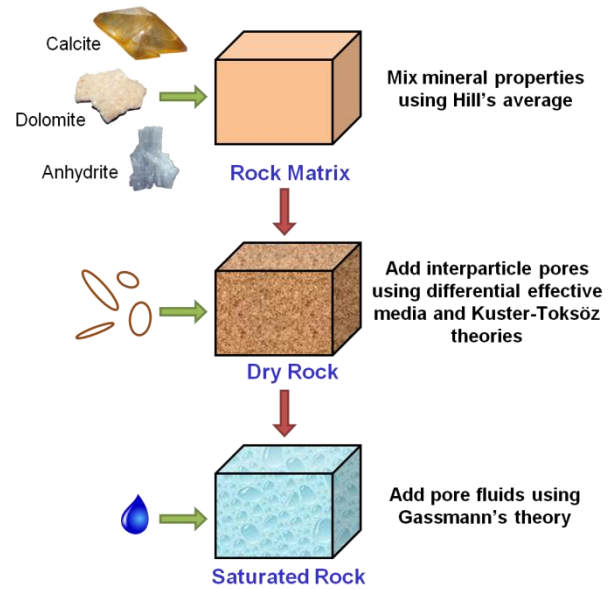


Fig. 3. PEM for carbonate combining the differential effective media, Kuster-Toksöz and Gassmann theories.

Nevertheless, Gassmann equation is sometimes believed not to be applicable in carbonates with a significant proportion of unconnected pores as it requires an equilibrated pore pressure throughout the whole rock. In order to address this issue, we used the T-matrix model (Agersborg et al., 2009) which not only takes into account the geometry of the pores but also the wave-induced fluid flow between connected pores. Fig. 4 shows the calibration of both models to one of the wells. Both models give a good fit in brine condition and the same qualitative hydrocarbon effect characterised by a drop of impedance and V_P/V_S ratio. Yet, there is an important quantitative difference in terms of oil saturation with the Gassmann-based model underpredicting the actual saturation and the T-matrix model slightly overpredicting the oil in place by a similar amount.

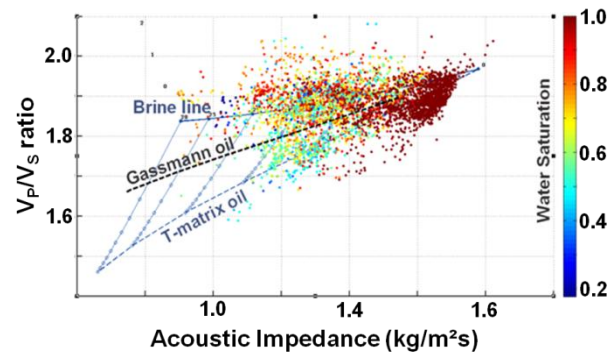


Fig. 4. Calibration of both Petro-Elastic Models to one of the well in the acoustic impedance versus V_P/V_S ratio domain.

Results

We start with an initial geomodel made of thick layers (thickness of around 60m) filled with a constant porosity. This coarse scale is sufficient to adequately model the low frequency seismic response and gives stable results in terms of inverted thickness and porosity. The analysis of the mismatch between the forward modelled synthetic seismic and the observed seismic data indicates where refinement is needed. Refining the geomodel from the initial coarse vertical description with the introduction of intermediate layers within the reservoir improves the quality of the match with the seismic data. The incremental improvement in quality is monitored until no further improvement is obtained by refining the thicknesses. After that stage, increasing the number of layers is detrimental to the robustness of the solution, both in terms of property and thickness evaluation.

Laterally stable inversion results are obtained for the thin tight zones (Tight Zone 1 and Tight Zone 2 in Fig. 5) that separate the reservoir intervals observed at the wells. The more porous layers of the reservoir model, labelled B1 to B3 in Fig. 5 exhibit significant lateral variations with well defined porous bodies.

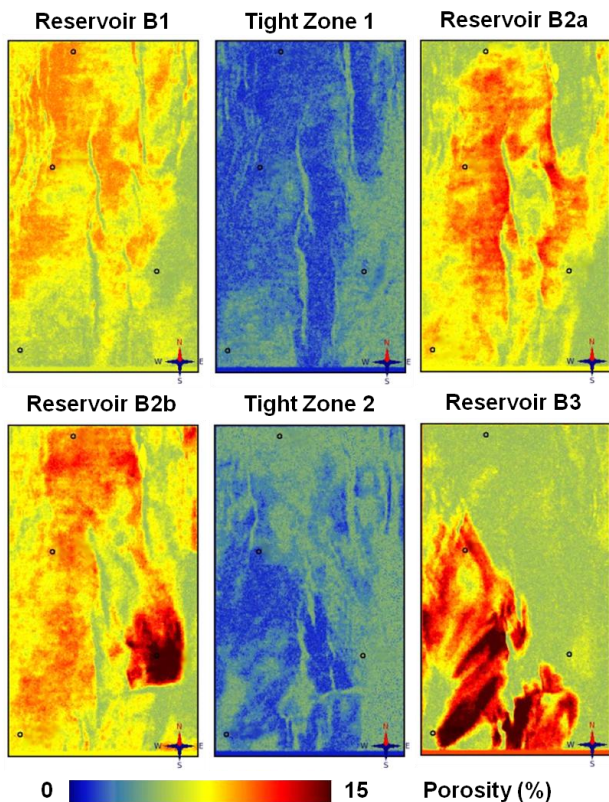


Fig. 5. Evolution of the porosity with depth. Both reservoir and tight zone intervals display lateral variations coming directly from pre-stack seismic data.

Different hypotheses were tested for the reservoir fluid content; water-only scenario was first tested, oil was then introduced in selected layers of the geomodel. Analysis of

the pre-stack residuals was used to quantify the improvement achieved by introducing oil in each of the three reservoir zones.

In B3 reservoir, we were able to significantly improve the seismic match of the geomodel by inverting for oil saturation in addition to porosity. Fig. 6 shows the inverted saturation and porosity spatial distributions obtained for one of this reservoir layer. The inverted oil saturation distribution appears geologically consistent. The improvement in terms of seismic match compared to the water-only case gives confidence in the fluid estimation.

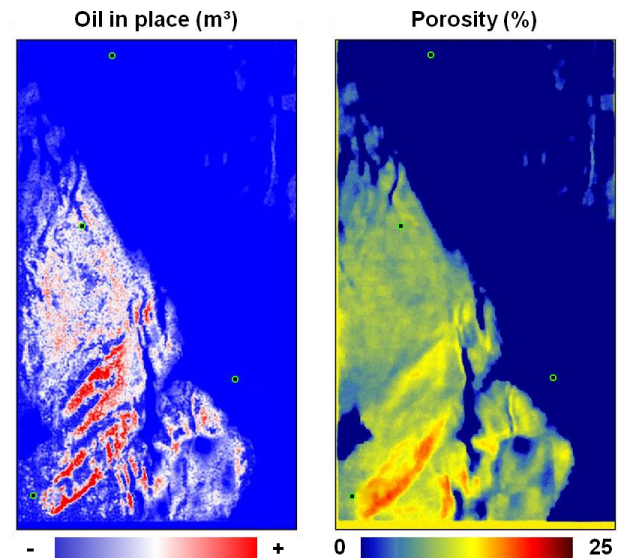


Fig. 6. Estimated oil in place (left) and porosity (right) at the top of B3 reservoir.

Limitations

As presented in the petro-elastic modelling section, the choice of PEM controls the absolute saturation values as the fluid substitution in the T-matrix PEM doubles the elastic impact compared to the extended Xu-White model. Therefore a quantitative estimation of the volume of oil in place is subject to the impact of that uncertainty.

We also investigated the possibility to characterise the geometry of the pore space as this is one of the input parameters of the PEM. We found out that inverting for the aspect ratio of the pores is a highly non-unique problem. Indeed, a mix of compliant cracks and stiff vugs has a similar elastic behaviour as a homogeneous interparticle porosity. Generally speaking, seismic data is only sensitive to the effective pore geometry or stiffness of the rock.

Nevertheless, when thin sections and CT scans from plugs are available, zones characterised by compliant and stiff pores can be identified at the well position. In favourable cases, this interpretation can be extrapolated away from the wells by using the inverted effective pore geometry which is a good indicator of the rock stiffness.

Conclusions

In this carbonate example, petrophysical inversion leads to stable results in terms of porosity and fluid content by efficiently decoupling their effect in the seismic modelling. Estimation of absolute saturation values is more difficult as it strongly depends on the PEM selected for fluid substitution. The inversion results expressed in rock properties are easy to understand and validate. Finally, "What-if" scenarios (e.g.: fluid type water/oil) are easy to implement as parameters and constraints are expressed in terms of petrophysical variables.

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