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Finding a Petro-elastic Model Suitable for Sim2seis Calculation

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SUMMARY

The petro-elastic model (PEM) is a necessary step in simulator to seismic modelling, intended to close the loop between the seismic and engineering domains. In this work, we discuss some fundamental issues within the conventional PEM algorithm, not commonly covered by published literature. Firstly, we explain the importance of the porosity rock model for the PEM. It is shown that both total/effective porosity models are able to generate satisfactory seismic results, provided that the density and bulk/shear moduli of the solid components are set correctly using an optimisation problem. We find the underlying connections between the simulation model parameterisation and the effective porosity model from the petrophysical domain. Finally, we discuss the effect of vertical upscaling on the seismic domain. We highlight the differences between property upscaling and reflectivity upscaling, and challenge the idea of developing a scale-dependent PEM based on Backus averaging. In addition to a sim2seis analysis, the results of this work have direct impact on seismic inversion via the PEM for pressure and saturation change or impedance change onto the reservoir grid.

Keywords: PEM, rock porosity model, simulation model, effective porosity, total porosity, upscaling, Backus averaging, reflectivity upscaling.

Introduction

The petro-elastic model (PEM) is a necessary step in simulator to seismic (sim2seis) modelling, intended to close the loop between the seismic and engineering domains. In this context, there are several studies in the literature that discuss the choice of the rock porosity model when constructing a PEM, taken from the petrophysics (Simm, 2007) and simulation model (Taggart, 2002) perspective. However, more importantly these concepts need also to be addressed in an integrated sim2seis study where the two disciplines are involved. In this work, the difference between the working definitions inherent in these domains is discussed, and a way of transforming between the two domains is determined. In the second part of this work, the issues arising from use of the PEM at the log and simulator scales is discussed. Previous studies address this problem by developing scale-dependent PEM equations. In this work, the effect of upscaling is evaluated in the seismic domain and it is shown that previous methods may not preserve the seismic response. A new concept of reflectivity upscaling is introduced as a possible solution to this problem.

PEM models – the Petrophysics versus simulation model domain

In theory, the rock model in the petrophysics domain can be very complex (Kennaird, 2006), with a varying number of volume fractions. The standard rock porosity model (Menger & Prammer, 1998) (Figure 1a) is a simple model which is commonly used in practice, being sufficient for the purposes of 4D seismic analyses as it is manageable, yet retains sufficient diversity to explain the 4D observations. In this model, the solid part is divided into two volume fractions mainly occupied by quartz and the other by dry clay minerals. The porosity is occupied by hydrocarbon and water (clay bound water, capillary bound water, free water). This model can be described either by total or effective porosity (Figure 1a). In the effective porosity model, the clay bound water is grouped with dry clay and defined as the volume of shale. For the total porosity model, it is possible to analyse the effects of the dry clay and clay bound water separately. The former model fulfils the underlying assumptions of Gassmann's theory regarding full pore space interconnectivity (Simm, 2007). The latter model however has also been used in a number of fluid substitution studies (Simm, 2007). Indeed, using numerical and analytical analyses, Grechka (2009) showed that under some conditions, the presence of disconnected porosity does not necessarily invalidate Gassmann's predictions.

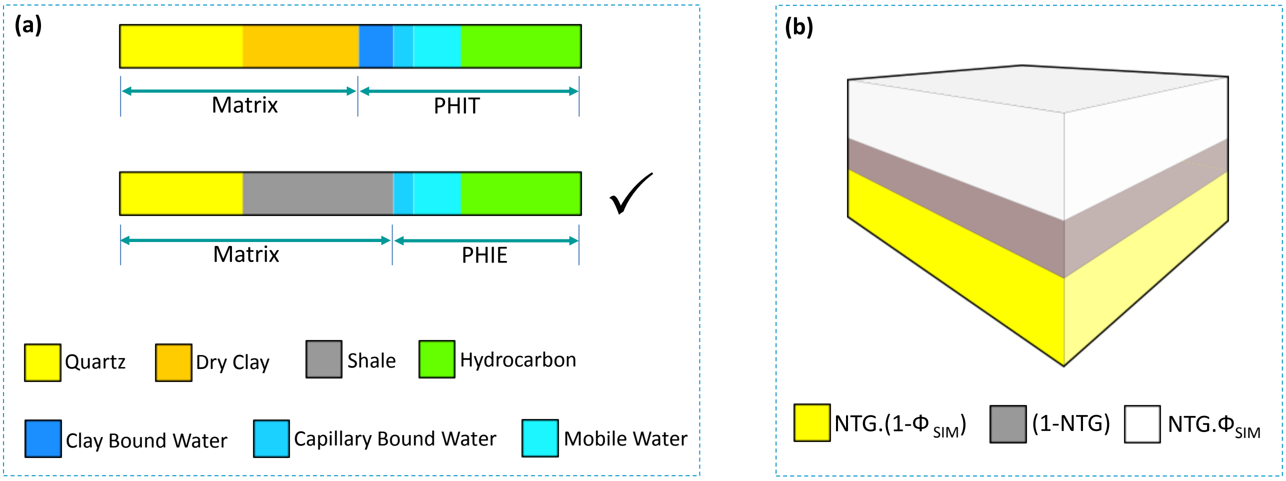

Figure 1 *(a) The standard rock porosity model, total porosity (top) and effective porosity (below). (b) The three component simulation model rock model. The standard rock porosity model based on effective porosity is linked to the simulation model rock model.*

Table 1 *Definitions involved with petrophysics versus simulation models.*

Petrophysics	Simulation Model
PHIE	$NTG \, . \, \phi_{SIM}$
V_{SH}	$1 - NTG$
V_Q	$NTG \, . \, (1 - \phi_{SIM})$

Our PEM calculations for a North Sea reservoir show that both total/effective porosity models are able to generate satisfactory results, provided that the density and bulk/shear moduli of the solid components are set correctly. This is a problem, as it is known that the clay/shale parameters are widely variable and reservoir dependent. Simm (2007) used a normalised bulk modulus versus porosity plot to QC the initial guess for the moduli. However, this approach is based on trial and error and there is some possibility that the selected values may not be the best. Here, to overcome this problem, an optimization algorithm is designed. The inputs to the algorithm are P-wave velocity (V_P), S-wave velocity (V_S) and density (ρ) logs, the volume fraction of the rock components, in-situ acoustic properties of the fluids, and a reasonable range for density and moduli of the solid components. For all of the possible combinations of input parameters, the PEM is evaluated and the output of this algorithm gives the best match to the V_P, V_S, ρ logs within the depth interval(s) of interest. In our analysis, this algorithm is used simultaneously over several wells to capture the most representative values. Supplementary information can be gained from this exercise to QC the log data and petrophysical evaluations. The cross-plots of the modelled impedance versus the impedance from wire-line log measurements indicate that the effective porosity model predictions are more scattered due to the presence of the clay bound water as part of the matrix. However, it is noted that despite the model differences at the log scale, the seismic responses of the two models are still directly comparable (Figure 2).

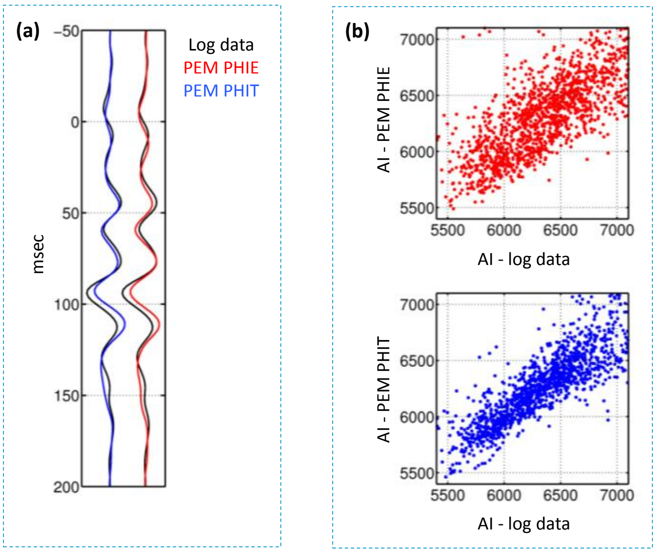

Figure 2 *(a) Seismic response is the full stack (0-35 degree) synthetic seismogram using the wavelet from well tie (dominant frequency ~ 24Hz). The seismic responses of PHIE and PHIT models are compared with seismic response of the measured logs. (b) The impedance calculated from measured logs versus the predicted impedance using (top) effective porosity and (below) the total porosity. The effective porosity model predictions are more scattered.*

In 4D seismic studies, there is no direct reference to the rock model arising from the simulation model. Pore volume is the original key rock component in the fluid-flow equations which is defined using intermediate parameters of porosity and net to gross (NTG) (Eclipse manual, Schlumberger). However neither porosity nor NTG are present as explicit terms in the fluid-flow equations, but are instead used in the expression

$$PV = Vol \,.\, \phi \,.\, NTG \tag{1}$$

where PV is pore volume, ϕ porosity and NTG net-to-gross thickness ratio. This equation for PV implies a three component rock model (Figure 1b). It should be noted that not all of the space defined by PV is available for fluid flow, as this is limited by relative permeability and capillary pressure curves bounded between the irreducible water saturation and residual oil saturation. In addition to the PV calculations, NTG is also used in the simulator to compute the effective area between two neighbouring cells for transmissibility calculations. The rock components used by the PEM in the petrophysical domain must be consistent with those used in the simulation model. As the petrophysical rock model based on effective porosity is simpler than the total porosity model, it is more convenient for relating to the simulation model. The petrophysical parameters of the effective porosity model are translated to descriptive terms in the simulation model in Table 1. These equations highlight the conceptual differences between the petrophysical definition of porosity (PHIT or PHIE) and the porosity defined in the simulation model. In other words, the corresponding quantity for petrophysical porosity in the simulation model is the pore volume, and not the simulation model porosity. Hence, care must be taken to ensure that the simulation model porosity is correctly included in integrated studies. Note that the choice of cut-offs in the NTG definition (Worthington & Cosentino, 2003) complicates the derived equations in Table 1.

PEM and scale

In an integrated sim2seis study, three different vertical scales are dealt with: log scale, simulation model scale, and the seismic scale. Differing concepts and approaches associated with the PEM scale are addressed in the literature (for example, Menezes et al., 2006 and Alfred et al., 2008). In this study we evaluate the effect of upscaling the log data to the seismic scale. An upscaling that maintains geological consistency is a good first choice approach, however the seismic responses are invariably different at each scale (Figure 3). Alfred et al., (2008) attributed the resultant upscaling error to a mixing of lithologies. However, we find that even in a geologically consistent upscaling in which mixing between sand and shale intervals is avoided, errors arise due predominantly to distortions of the phase spectrum of the reflectivity series. To avoid this, in this work seismic waveform inversion is used to invert for the rock model at the coarser scale to generate the closest seismic response to that created by modelling from the log scale (Figure 4). It should be noted that the resultant model from reflectivity upscaling does not necessarily represent the geology at the coarser scale. Our results show that the order of applying the upscaling and PEM operations does not make a noticeable difference in the seismic domain (Figure 3b). These results differ from the approach of Menezes et al., 2006, who develop scale dependent PEM equations based on Backus averaging. It is suggested that there is no universally applicable equation that can be used to upscale the properties in order to preserve the seismic response. As a numerical recipe, the suggestion is to modify the wavelet used for seismic modelling to compensate for the phase and amplitude spectrum distortions resulting from the property upscaling. Our recommendation is to tie the observed trace at the simulation model scale, rather than the well-log scale.

Conclusions

The key conclusion of this study is that the differences between the petrophysical domain (log data) and the engineering domain (reservoir simulation model) need to be addressed when developing the petro-elastic model for 4D seismic studies. This is also of crucial importance when modelling the 3D seismic response from the reservoir model or inverting the seismic to properties defined on the reservoir grid. It is found that the effective porosity model provides agreement, provided our transformation between properties is followed. Finally, the best form of upscaling is one that is based on reflectivity, and not property averages.

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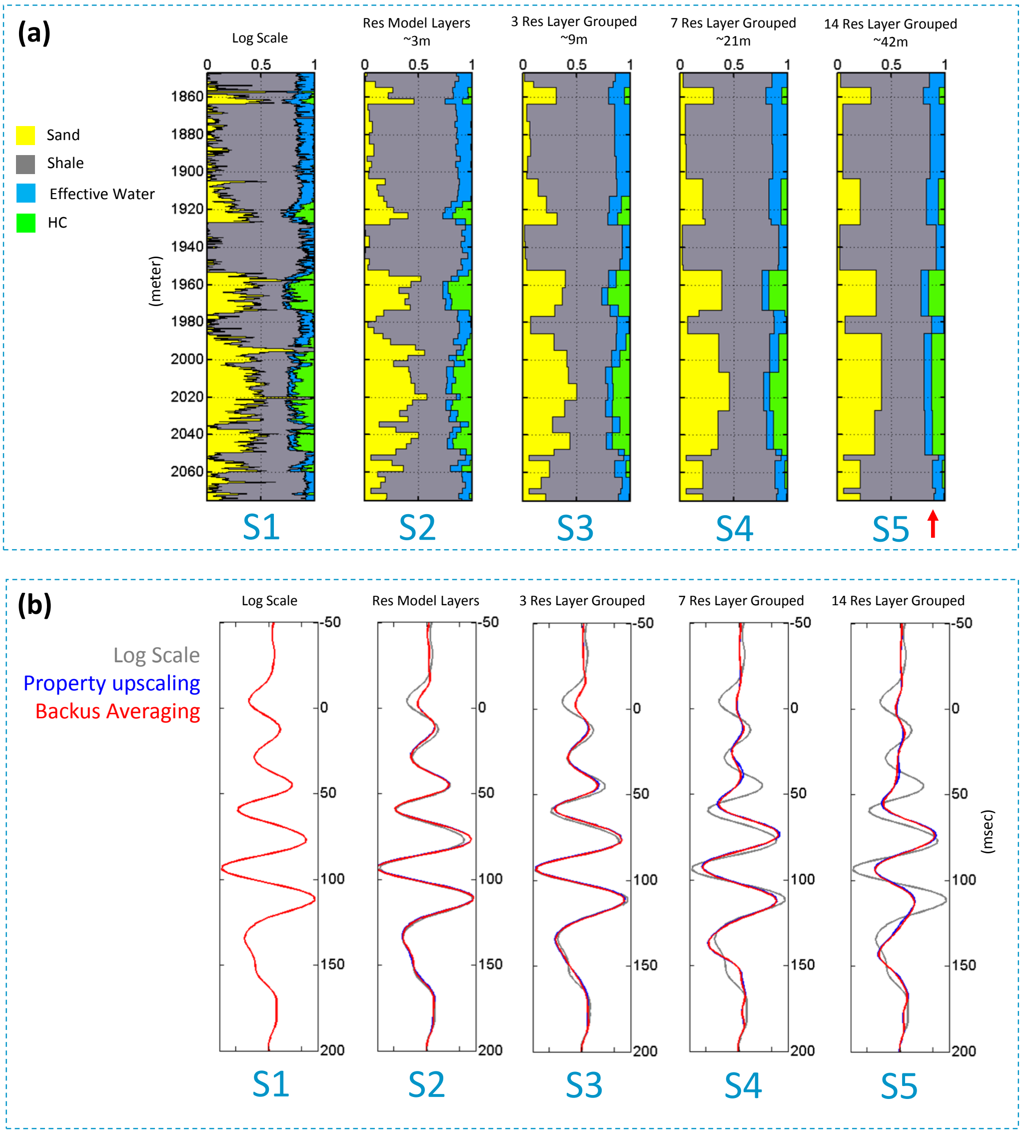

Figure 3 *(a) Geologically consistent upscaling of the rock model within the simulation grid. S1: log scale, from S2 to S5, 1, 3, 4, and 14 layers of the simulation model are grouped respectively. Sand and shale intervals are preserved during upscaling. (b) The corresponding seismic responses to S1-S5. The sequence of PEM and upscaling (property upscaling vs. Backus averaging) does not make a noticeable difference in the seismic domain.*

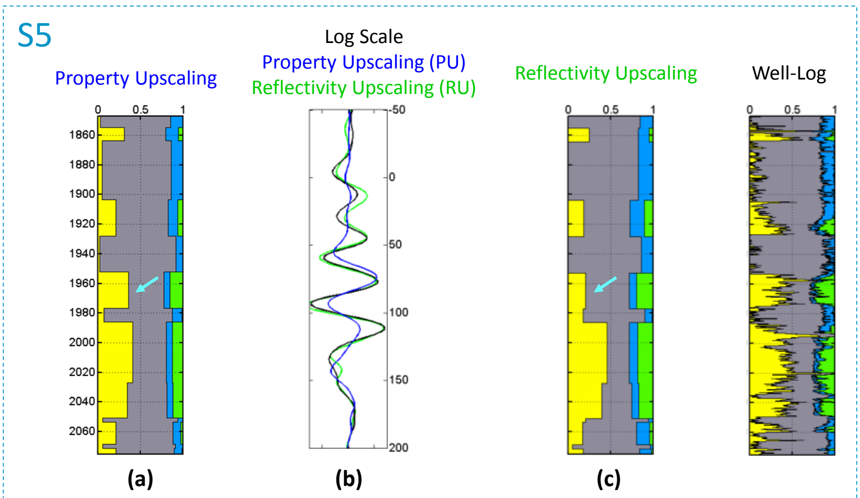

Figure 4 *Property upscaling versus reflectivity upscaling for S5. (a,b) The property upscaling does not preserve the seismic response,(a,b,c) the reflectivity upscaling does not necessarily represent the geology at the coarser scale.*