P075

A Saturation Law for Quantitative 4D Seismic Analysis of a Turbidite Reservoir Undergoing Waterflood

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SUMMARY

Reservoir management can be very much improved by increasing our knowledge of fluid changes within the field. Time-lapse seismic can offer this information provided an accurate relationship between the fluid-bulk modulus estimated from seismic and the true reservoir saturation condition is known. This relationship is generally simplified by ignoring the interaction of fluid, heterogeneity and seismic at various scales, thus significantly increasing errors and uncertainty in saturation estimates. To improve the relationship, a reservoir-based saturation law is developed with specific application to a turbidite reservoir. This geological architecture allows us to construct suitable conceptual models such that analytical solutions can be derived. The resulting law takes into account both saturation and geological heterogeneity when estimating saturation from seismic. Numerical tests based on flow simulation and seismic calculation show that this law can accurately predict the true reservoir saturation to within 1 to 2 percent, whilst laws not incorporating this reservoir information can achieve 3 to 8 percent and are strongly dependent on porosity and saturation fluctuations. Whilst the new approach requires data gathered from fine scale simulations and analogue outcrops, the improvement in accuracy and reduction in uncertainty may well be advantageous.

Introductory background

In dynamic reservoir management, accurate monitoring of saturation change and its lateral distribution are important for evaluating the overall performance of a waterflood. An emerging tool which can supplement production and saturation logs for this purpose is *4D* seismic imaging. Techniques for estimating saturation changes from seismic attributes, independently of the pressure change overprint, are now being developed (see Ribeiro and MacBeth 2006 for details). However one recognised challenge in the use of such seismic techniques is the uncertain and inexact relationship that exists between the effective fluid bulk modulus estimated from seismic and the actual fluid saturation state within the reservoir or inferred from well data. If *4D* seismic is to be used in a precise quantitative manner, a key objective is to derive a saturation law that permits a true measure of saturation from seismic in the presence of reservoir heterogeneity. More specifically, a formula is required for the effective fluid bulk modulus κ_f^{eff} that appears in the seismic-scale version of the Gassmann (1951) formula. The work here addresses this objective by developing an equation for κ_f^{eff} in terms of the pore-volume weighted average saturation $<S_W>$, which necessarily requires the statistics of the internal geological architecture and simulation output - information which has not been utilised to constrain this problem in the past. Water displacing oil in an oil-water system is considered at this stage.

Saturation heterogeneity and partial geological heterogeneity

In most laboratory-based and seismic studies to date, the effective fluid bulk modulus, κ_f^{eff} is computed as a harmonic average of individual fluid bulk moduli (κ_O and κ_W for oil and water respectively), weighted by their respective saturations, S_O and S_W (see, for example, Domenico 1976). By comparison, the mean saturation $<S_W>$ is a pore-volume weighted average. For a homogeneous geology, this defines the κ_f^{eff} versus $<S_W>$ reference curve *L* in Figure 1, which is only strictly valid for a completely homogeneous saturation state distribution defined at a snapshot in time in the reservoir.

A refinement of the basic saturation law above to the case of water displacing oil in a seismic-scale sand volume under more realistic conditions follows Kirstetter et al. (2006). This recently introduced discrete state model assumes saturation heterogeneity, and permeability or mobility variations in an otherwise uniform geology (constant porosity). Here, the saturation trajectory from pre-production to production end-point is a function of the volume fraction F_V of the sand body which has been swept, and in the general case it is given by

$$\kappa_f^{eff} = F_V[(1-\alpha)\kappa'_w + \alpha\kappa''_o] + (1-F_V)\kappa'_o\,, \qquad (1)$$

where F_V is given by

$$F_V = \frac{<S_w> - S_{wc}}{1-(1-\alpha)S_{or} - \alpha S'_{or} - S_{wc}}\,, \qquad (2)$$

and α is the fraction of the sand body behind the waterfront occupied by by-passed oil (with a macro-scale residual oil component S'_{or}). Both α and S'_{or} (and hence F_V) change with production time, whilst the other components remain fixed by the particular reservoir rocks. The fluid bulk modulus κ'_O is for the uniform mix of connate water plus initial pre-production oil and hence is given by the harmonic average; likewise κ''_O is the corresponding result for the displacing water plus remaining oil saturation, S'_{or}, in the by-passed regions; and κ_W' for a mixture of displacing water plus pore-scale residual oil saturation, S_{or}. If the displacement process progresses slowly and efficiently enough for only minimal pore-scale residual oil to be left behind, α=0 (the *P1* trajectory in Figure 1). If production proceeds quickly and by-passed oil is left behind, α is likely to be non-zero (but relatively unknown in practice) - this gives trajectory *P1'* in Figure 1.

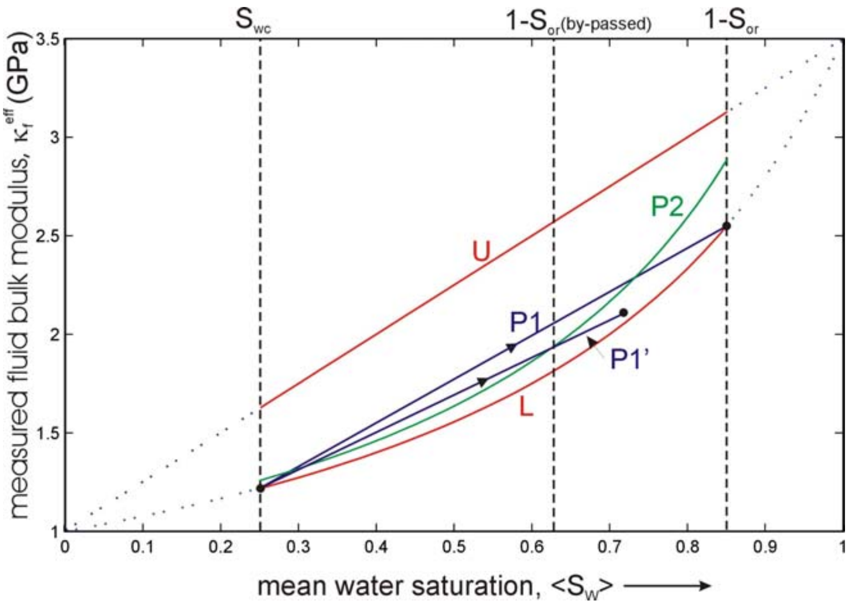

Figure 1. Predicted relationships between effective fluid bulk modulus κ_f^{eff} and the true pore volume weighted mean water saturation $<S_W>$ for a two-phase (oil-water) system under waterflood. *L* – based on the homogeneity assumption; *P1* – for the smooth displacement of oil with α=0; *P1'* – if additional macro-scale by-passed oil is left behind (α is chosen arbitrarily to be 0.3). *P2* – the proposed new saturation law based on the geology and saturation fluctuations in the reservoir.

Saturation and geological heterogeneity for turbidite reservoirs

In practice, the derivation of a saturation law is specific to the geology of the reservoir. Thus we initially choose to focus on channelised turbidite reservoirs, utilising the model of Stephen et al. (2001). Consequently, from the seismic perspective each channel sand body is considered to be made up of a series of thin, homogeneous and horizontal sand beds sandwiched between shale eroded to differing extents (MacBeth et al. 2005). To obtain the desired saturation law we apply Backus (1962) and perturbation theory to derive a transformation for the observed fluid bulk modulus in terms of the mean fluid bulk modulus $<\kappa_f>$ (which is defined as the harmonic average of κ_O and κ_W weighted according to $<S_W>$)

$$\kappa_f^{eff} = <\kappa_f> \left(1 + a\sigma_1^2 + b<\kappa_f>^2 \sigma_2^2 + c<\kappa_f>\sigma_3^2\right) \tag{3}$$

where *a*, *b* and *c* depend on the mean porosity $<\phi>$ and material and fluid constants. The bracketed correction term in (3) is a weighted sum of the variances of the bed-scale fluctuations in porosity $\delta\phi$ and saturation δS_W

$$\sigma_1^2 = \frac{1}{N}\sum_{i=1}^{N}(\delta\phi)^2, \qquad \sigma_2^2 = \frac{1}{N}\sum_{i=1}^{N}(\delta S_w)^2, \qquad \sigma_3^2 = \frac{1}{N}\sum_{i=1}^{N}(\delta\phi\delta S_w)^2. \tag{4}$$

A typical evolution of the saturation distribution is shown in Figure 2.

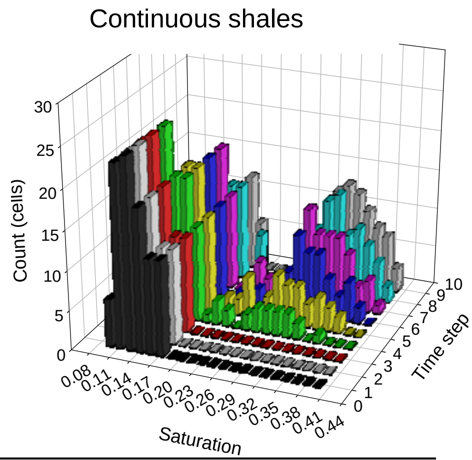

Figure 2. Histograms of saturation distributions as a function of production time for one of the 2D models analysed in this study. These particular statistics correspond to a central column through the simulation model for the continuous shale model. The histograms are drawn for 30-day time steps, ranging from 0 to 270 days. As the waterfront progresses through the reservoir the spread in saturation, σ_2, will at first grow over time but then reach a maximum of around 0.2 before decreasing slightly (see also Figure 3).

For turbidite reservoirs the porosity term σ_1 is typically small (~0.02), while simulation runs have shown the saturation-related standard deviation σ_2 to be much larger (~0.2). The covariance term σ_3 remains quite small when the porosity and saturation variations are independent ($\approx$0.04). It therefore appears that saturation fluctuations dominate, and the estimates from the *P2* relation are mostly independent of the reservoir porosity fluctuations.

Test of new saturation law using numerical flow simulation studies

To understand in more detail the variation in porosity and saturation during production, and their impact on the κ_f^{eff} versus $<S_W>$ relation, the new formulation in (3) is tested by performing a number of numerical flow simulations of lateral displacement of an oil by a waterflood in a single channel sand body. The flow modelling produces a range of distinct saturation distributions, from which the spatial statistics of the waterflood process can be extracted and fed into (3) at various time steps. Exact evaluation of the seismically observed κ_f^{eff} is obtained by numerical calculation using the Gassmann and Backus equations applied to fine-scale simulations. Four basic types of model are considered: continuous shales, no shales (hence fully amalgamated sands), and two other models with partial shale erosion.

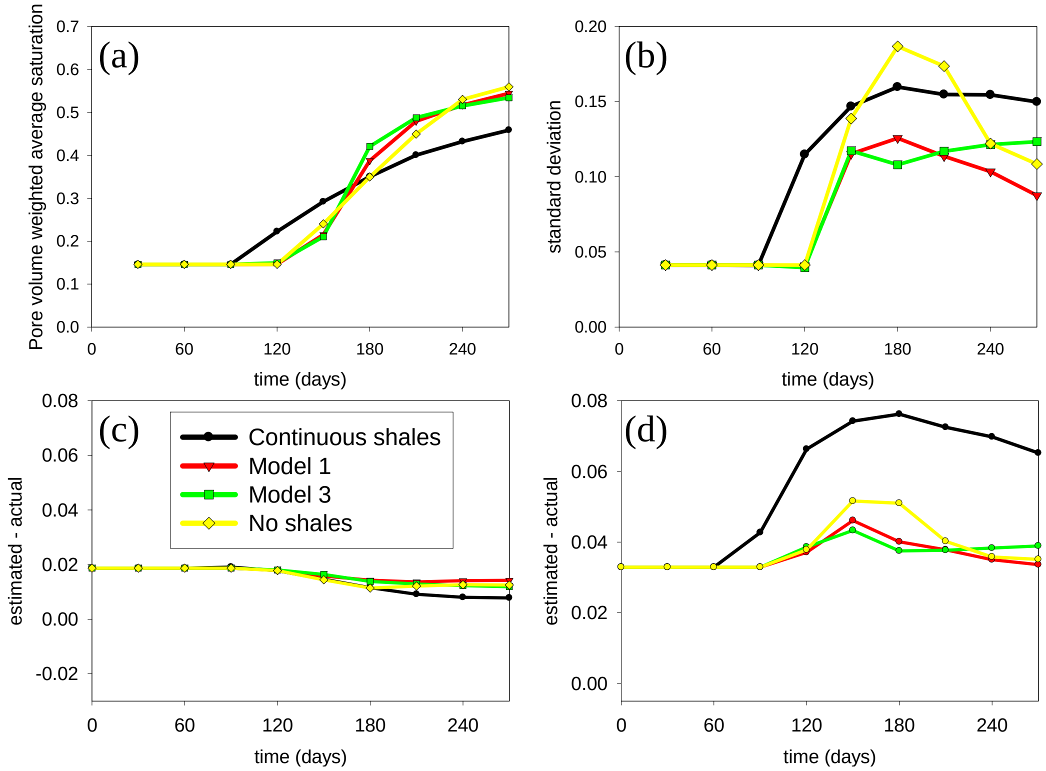

Figure 3. (a) mean saturation from the simulation; (b) standard deviation of the vertical saturation distribution; (c) saturation inversion error – defined as the error between the saturation obtained from (3) and the mean saturation from flow principles. (d) inversion error if *L* curve alone is used.

The corresponding absolute error in (3) is observed to be no more than 1 to 2 percent (Figure 3c), which is small when compared to the error obtained from assuming κ_f^{eff} is represented by curve *L* (3 to 8 percent). The continuous shales model contains the largest set of errors. As expected, the errors in the estimates using *L* closely mirror the variations in the saturation distribution and also grow with increasing porosity fluctuation. The errors in the estimates of $<S_W>$ from *P2* are more independent of these fluctuations as they have been corrected using the bracketed term in (3). Estimates based on the *P1* (α=0) law from (1) give errors intermediate between those for *L* and *P2*, but are again dependent on the porosity and saturation fluctuations. The results for both the 2D and 3D models are similar.

Discussion and conclusions

Estimates of fluid-bulk modulus extracted from seismic are biased by the internal architecture of the reservoir, so that seismic estimates of saturation do not correspond to the true (pore volume weighted) average saturation. In the simplest case of a homogeneous reservoir with locally uniform saturation, a harmonic average of the fluid properties is sufficient to determine the effective fluid bulk modulus. However this is inappropriate in a realistic, producing reservoir, where heterogeneity must be taken into account. Both seismic and flow-based estimates are complicated by geological and saturation heterogeneity, but in different ways. Seismic estimates cannot therefore be regarded as a direct indicator of the fluid properties, and should be corrected to align them with the fluid flow domain. For a turbidite reservoir, the required correction factor is observed to depend on the spread of saturation and porosity values. Using this information, the *P2* formulation developed here provides predictions correct to 2 percent accuracy, but must be calibrated by fine-scale geological understanding, as well as directly through flow simulation. The usual assumptions of homogeneity such as *L* require no such input but are more erroneous, whilst *P1* and *P1'* demand knowledge of the levels of connate water, residual oil and by-passed oil. This work has particular impact in those reservoirs for which saturation plays a dominant role such as the Nelson field (e.g. McInally and Lopez, 2003). More generally, it will provide a useful correction to pressure-saturation inversion procedures, simulator to seismic modelling, or *4D* feasibility studies.

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