Modelling Inversion for Fluid Parameters in Enhanced Oil Recovery

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Summary

We study the feasibility of detecting changes in pore pressure and fluid content from time-lapse impedence measurements derived from surface seismic, with only a limited knowledge of the rock parameters. The inversion procedure is non-linear, and the quality of the results depends on the amount of noise in the data and the estimates of the reservoir rock properties at each location. We obtain reasonable results from synthetic data with a realistic uncertainty in the rock properties, assuming the noise level is fairly low.

Introduction

PanCanadian is currently acquiring a 4-D multi-component data set over a portion of the Weyburn field, located in south-eastern Saskatchewan. The purpose is to monitor the tertiary CO_2 flooding of carbonate formations that still contain significant amounts of oil. The aim of this study is to find the best way of using this data to map out features that have an impact on the reservoir development. The parameters that are often derived in 4-D work are the pore pressure and the water saturation, although we are forced to modify this by the nature of a CO_2 flood.

Theory

The target of interest is a relatively thin unit, making tuning an issue. We therefore consider a data set consisting of time-lapse seismic impedence measurements, output from inversions (to take care of the thin layer), which is also the data set used by Tura and Lumley (1999). Problems associated with extracting accurate time-lapse seismic impedences shall not be addressed here. We expect (Ip,Is) to change as a function of the pore pressure changes in the rock and the fluid content of the rock. The effect of pressure changes must be found empirically from core studies (e.g. Zhang and Bentley, 1999), while the fluid changes can be modelled using Gassmann's equations. The forward perturbational model can be formulated as follows:

$$\boldsymbol{\delta}\mathbf{d} = \mathbf{G}(p_0, k_{f0}, \rho_{f0}, \mu_0, k_{d0}, \phi)\boldsymbol{\delta}\mathbf{m} \tag{1}$$

where $\boldsymbol{\delta}\mathbf{d} = [\delta Ip, \delta Is]^T$, $\boldsymbol{\delta}\mathbf{m} = [\delta p, \delta k_f, \delta\rho_f]^T$, G is a 2x3 Frechet matrix whose elements are $G_{ij} = \frac{\partial d_i}{\partial m_j}$ and can be calculated analytically using Gassmann's equations, fluid mixing relations and empirical rock-pore pressure relations. Above, $p, k_f, \rho_f, \mu, k_d, \phi$ refer to the pore pressure, fluid bulk modulus, fluid density, dry rock shear modulus, dry rock bulk modulus and porosity, respectively. We have chosen our model parameters to be the basic fluid properties rather than component saturations. This is necessary since the relation between the relative amounts of oil/ CO_2/brine in a mixture and the corresponding fluid bulk modulus/density is not unique: for single-contact mixing the limited miscibility alters the properties of the oil and CO_2, making for a complicated (although tractable) relationship; however, in multi-contact mixing the properties of the fluids are dependent on the fluid mixing history (Lake, 1989). In a sense this is a more realistic model even for the more commonly studied case of water flooding, since gas coming out of solution where pore pressure drops is not incorporated in the simple oil/water saturation model.

The non-linear inverse problem can be solved through iteration:

$$\begin{aligned}
\delta\mathbf{d}^i &= \mathbf{d}^f - \mathbf{d}(\mathbf{m}^i) \approx \delta\mathbf{d}^{obs} - (\mathbf{d}(\mathbf{m}^i) - \mathbf{d}(\mathbf{m}^0)) \\
\delta\mathbf{m}^i &= \mathbf{G}^*(\mathbf{m}^i)\delta\mathbf{d}^i \\
\mathbf{m}^{i+1} &= \mathbf{m}^i + \delta\mathbf{m}^i, \quad i = 0,1,2\ldots
\end{aligned} \tag{2}$$

where the superscript indicates the i^{th} iterate, and $\mathbf{G}^*$ represents the generalized inverse (there are more unknowns than data, at any spatial location). The non-linearity of the forward model means that $\mathbf{G}^*$ must be re-calculated as the model is updated. Landro (1999) has used a second order (in pore pressure) forward model with constant coefficients to find a one step inverse. We consider this an unnecessary simplification, especially in light of the large perturbations expected in the fluid bulk modulus. We note that the model parameters $(\delta p, \delta\kappa_f, \delta\rho_f)$ are not independent, since changes in pressure result in fluid bulk modulus and density changes. We cannot, therefore, attribute changes in fluid properties purely to compositional changes, although we feel this will be the dominant factor.

We can obtain an good solution if our experimental and theoretical relations are correct, the perturbations don't lie in the model null space and we know the precise initial state of the reservoir rock i.e. $(p_0, k_{f0}, \rho_{f0}, \mu_0, k_{d0}, \phi)$. The challenge is to solve the inverse problem with an imperfect knowledge of the rock's initial state. We assume that we have a measure of P-impedence of the rock from the baseline seismic, and calculate estimates of all other variables based on statistical relations derived from log studies.

Example

We present some results using flow simulation data for a pattern of seven horizontal well injectors. The flow data was calculated using Geoquest's E-300 compositional simulator. The rock parameters at each grid location are created from a probabilistic model generated by well logs, and are spatially arranged to have P-wave velocity increasing from the bottom to the top of the map. A rather optimistic level (1% of Ip,Is) of random noise is added to the impedence data, although this corresponds to 7-100% of the size of the perturbations we're trying to detect. The resulting plan view maps for fluid bulk modulus changes during CO_2 flooding are shown in Figures 1 and 2, and we see generally good results. The inversion degrades towards the top of the maps, which is where the rock is hardest (highest velocity), and consequently most insensitive to fluid changes.

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References

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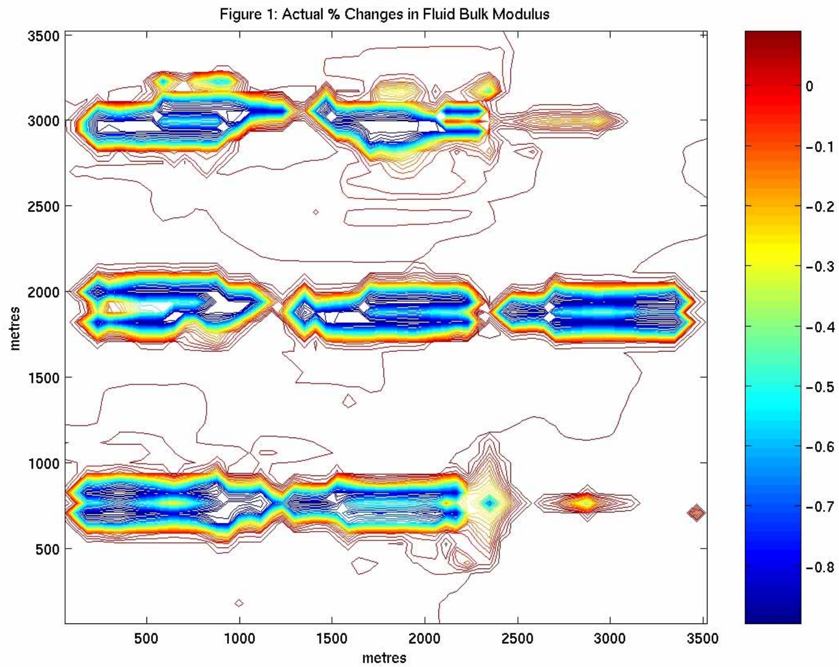
Figure 1: Actual % Changes in Fluid Bulk Modulus
metres
metres
500
1000
1500
2000
2500
3000
3500
0
−0.1
−0.2
−0.3
−0.4
−0.5
−0.6
−0.7
−0.8

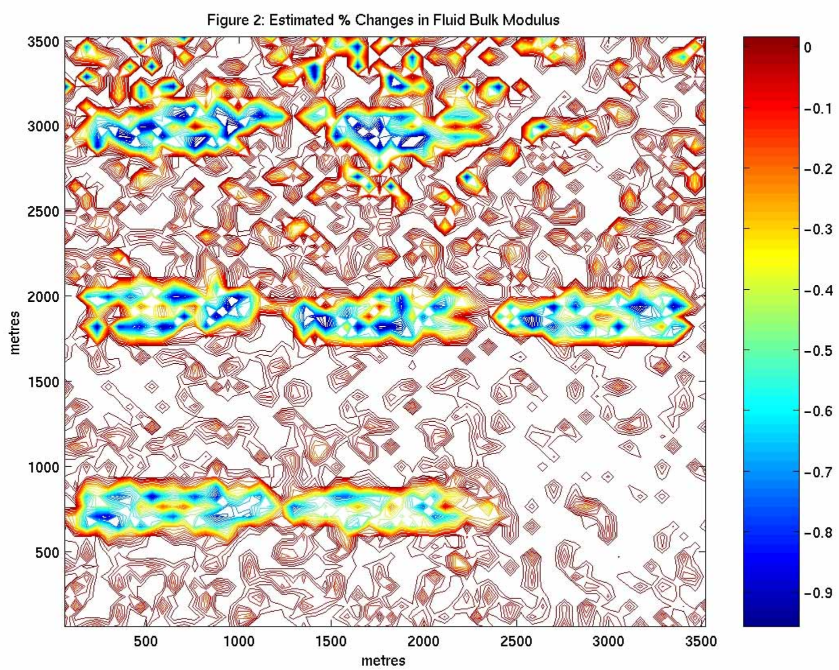
Figure 2: Estimated % Changes in Fluid Bulk Modulus
metres
metres
500
1000
1500
2000
2500
3000
3500
0
−0.1
−0.2
−0.3
−0.4
−0.5
−0.6
−0.7
−0.8
−0.9