Determining reservoir parameters from log and core data: a case study from the North Sea

Yan Jun\textsuperscript{1,2}, Enru Liu\textsuperscript{2} and Xiang-Yang Li\textsuperscript{2}

\textsuperscript{1}Edinburgh University
\textsuperscript{2}British Geological Survey, Scotland, UK

Summary
This paper presents an integrated approach to derive reservoir parameters from core and well-log data in clay-sand mixtures. These include formation parameters such as porosity, shale volume, clay content, permeability, and seismic parameters such as elastic moduli and anisotropy coefficients. Firstly we use a 'core to log calibration' approach to determine the formation parameters. Then this information is fed into the Xu-White model (1995) to estimate seismic parameters. Test from the North Sea data shows that precise predictions of the reservoir parameters can be made.

Introduction
Various models and theories have been proposed to understand the fluid-rock interaction in hydrocarbon reservoir for the purposes of lithology prediction and fluid substitution. These may include, for example, Gassmann [1951] theory, Kuster-Toksöz model [1974] etc. Recently, Xu and White (1995) combined several of these models and proposed a practical method (the Xu-White model) for velocity prediction in clay-sand mixtures. However, the Xu-White model uses the time-average equation (Wyllie et al., 1956) for porosity and shale volume, which is only suitable for consolidated formations, and does not work well for rocks with loose matrix and fractures, and rocks containing fluids, such as gas and live oil. To overcome these weaknesses, here we propose a modified approach. Firstly, a 'core to log calibration' is used to build a relationship between well-log and core data to derive porosity, shale, clay and permeability, which compensates for the effects of lithology, fluid, temperature, pressure and other factors. Secondly, the Xu-White model is used to predict elastic moduli and estimate anisotropy coefficient in clay-sand mixtures. The approach is applied to a dataset from the North Sea, which contains cores and logs in depth ranges from 12050 to 13200 ft.

Estimate formation parameters
We use linear and non-linear regression to build the relationship between core measurements and log data, and estimate the formation parameters as follows:

**Porosity:** According to core porosity and density log, we obtain

\[ \Phi = -0.607\rho + 1.53, \]  \hspace{1cm} (1)

where, \( \Phi \) is the total effective porosity, \( \rho \) is the density log \((g/cm^3)\).

A corrected porosity is used for shale correction

\[ \Phi^* = \frac{\rho_{ma} - \rho}{\rho_{ma} - \rho_w} - (V_{sh} - V_{cutoff}) \frac{\rho_{ma} - \rho_{sh}}{\rho_{ma} - \rho_w} \times 0.01, \]  \hspace{1cm} (2)

where, \( \Phi^* \) is the corrected porosity, \( \rho_{sh} \) is the shale density, \( V_{sh} \) is the shale content \((\%}\), \( \rho_{ma} \) is the matrix density, \( \rho_w \) is the fluid density and \( V_{cutoff} \) is the shale cutoff value \((\%}\).
**Shale volume:** The relationship between shale volume \( V_{sh} \) and Gamma-ray log \( GR \) is obtained by non-linear regression as

\[
V_{sh} = 10^{1.245GR + 0.6902},
\]

and the shale volume index \( GRI \) can be estimated by the gamma-ray values \( (GR) \)

\[
GRI = \frac{GR - GR_c}{GR_s - GR_c},
\]

where \( GR_s \) and \( GR_c \) are the gamma-ray counts for the sand and clay separately.

**Clay content:** Similar to the shale volume, the clay content \( V_{cl} \) is found to be

\[
V_{cl} = 10^{0.985*GRI + 0.3528}.
\]

**Permeability:** Porosity and shale are believed to control the permeability in clay-sand mixtures. According to core data, following regression relationship for permeability \( K \) is found to be appropriate in the study area.

\[
K = 8.7096 \cdot 10^4 \frac{\Phi^{5.78}}{V_{sh}^{1.36}}.
\]

**Predict seismic parameters**

**Elastic moduli:** The model proposed by Xu & White [1995] based on Kuster & Toksöz (1974) and scattering theory is used to compute elastic moduli, including \( K_d \) and \( \mu_d \) - bulk and shear moduli for dry frame respectively, \( K_m \) and \( \mu_m \) - bulk and shear moduli for mixture, \( K_f \) and \( \mu_f \) - bulk and shear moduli for fluid. Using these elastic moduli, the P-wave and S-wave velocities can be predicted based on Gassmann’s equations(1951). The shear-wave velocity \( V_s \) is \( (\rho_d/\rho_f)^{1/2} \), where \( \rho_k = \rho_m(1 - \Phi) + \rho_f \Phi \), with \( \rho_k, \rho_m, \rho_f \) are the density of bulk, matrix and fluid respectively.

**Anisotropy coefficient:** From elastic moduli we can predict S-wave velocity using the modified Xu-White model, and the anisotropy coefficient in turn can be estimated using the velocity relationship of shear-wave in horizontal and vertical directions by dipole sonic log. Equation (7) describes this relationship. The anisotropy coefficient \( m_s \) is determined by Equation (8),

\[
V_{s \perp} = \sqrt{2198 + 0.954 \cdot V_{s||}^2},
\]

\[
m_s = \frac{V_{s||} - V_{s \perp}}{V_{s||}}.
\]

where, \( V_{s||} \) and \( V_{s \perp} \) are the velocities of shear-wave in horizontal and vertical directions, and \( \overline{V} \) is the average shear-wave velocity for \( V_{s||} \) and \( V_{s \perp} \).

**Results**

We test the method on the field data from the North Sea. The input data include log and core data. The log data consist of caliper log \( (CAL) \), gamma-ray log \( (GR) \), density log \( (DEN) \), self-potential log \( (SP) \), interval transit time log \( (DT) \) and dipole S-wave velocity \( (V_{s||}) \) log. The core data include porosity(\( \Phi \)),
shale volume ($V_{sh}$) and permeability ($K$) samples analysis. Because of the uncertainties, the original logs cannot be used as input directly, and the 'core to log calibration' should be done before using the Xu-White model. This calibration includes the following six key steps:

1. curve editing and rebuilt, 2. curve depth correction, 3. deviated well correction, 4. core depth reposition, 5. core resolution matching, 6. core to log relationship.

As an example, Figure 1(a) shows a relationship of 'core resolution matching' using a filtering technique. Comparing the result of cross-plot analysis, we can find that the linear relationship has been improved by 'core resolution matching', and as expected the scattering is much small with a correlation coefficient of regression ($R$) of 0.936 (as compared with the correlation coefficient of 0.735 before core resolution matching).

Figure 1(b) shows the relationship of horizontal and vertical S-wave velocities in the real data. Figure 1(c) shows parts of the output for reservoir log parameters, including porosity, shale volume and water saturation, original density, caliper and gamma-ray logs. Figure 1(d) shows the estimation of the anisotropy coefficient ($m_s$) from 12050 to 13200 feet in depth.

Conclusion

A method has been developed which provides an integration between log and core data, to determine effective porosity ($\Phi$), shale value ($V_{sh}$), clay content ($V_{cl}$), water saturation ($S_w$) and permeability ($K$), and also to estimate the elastic moduli and hence S-wave velocity and anisotropy coefficient. The results show that this integrated approach can provide estimates of reservoir parameters.

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References


Figure 1: The examples of 'core to log calibration' and parameters output