**Improved Fluid Indicator Prediction Using Fluid Bulk Modulus Inversion**

**Introduction**

Seismic amplitude versus offset (AVO) based inversion techniques have been used in the seismic quantitative interpretation workflow for South East Asia region resulting in many hydrocarbon discoveries (Singh et al., 2009; Ahmad Munif et al., 2019; Ghosh et al., 2010). In this work, we extend the linear AVO fluid factor inversion equation (Russel, Gray and Hampson, 2011) in such a way that pore fluid bulk modulus \(K_f\), shear modulus, porosity parameter and density can be estimated using standard AVO least-squares extraction. Typical value of \(K_f\) for gas is in the order 0.1-0.6 GPa, oil 0.9-1.9 and brine above 2.3 GPa. The primary rationale for this development is thus to make use the significant difference in \(K_f\) values between oil, gas and brine feasible during the inversion as described in Mad Sahad et al. (2020). The ability to immediately extract \(K_f\) from seismic data gives a vast opportunity to predict the reservoir and background fluid and utilize them as a quantitative direct hydrocarbon indicator.

To showcase the effectiveness of fluid bulk modulus inversion for real data application, the fluid bulk modulus inversion is applied on the 3D seismic data acquired in Malay basin. The result in terms of direct hydrocarbon indicator using pore fluid bulk modulus values is compared with those from rock physics-based hydrocarbon classifier (RPHC) technique (Ahmad Munif et al., 2019) applied to the same dataset.

**Reflectivity and Amplitude Versus Offset (AVO) in isotropic media**

The Gassmann – Biot theory (Gassmann, 1951; Biot, 1956) is a basis for the fluid substitution problem, i.e. predicting saturated-rock velocities from dry-rock velocities, and vice versa (Mavko, Mukerji and Dvorkin, 2009). The effective (saturated) bulk moduli, \(K_{sat}\), can be related to the dry rock, \(K_{dry}\), through the following relationship

\[
K_{sat} = K_{dry} + \beta^2 M
\]

\[
\mu = \mu_{dry} = \mu_{sat}
\]

where \(\beta = 1 - \frac{K_{dry}}{K_m}\) is the Biot coefficient defined as the ratio of pore-volume change to bulk-volume change at constant pore pressure; \(\Phi\) is the porosity of the rock; \(K_m\) is the solid grain mineral bulk modulus; and \(\frac{1}{M} = \frac{\beta-\Phi}{K_m} + \frac{\Phi}{K_f}\) is the inverse Gassmann parameter (Russel, Gray and Hampson, 2011) exhibiting component of porosity, grain mineral and fluid in the saturated bulk modulus.

By using the relationship \(f = \beta^2 M\) in Equation (1) and P-wave AVO reflectivity function for an incident P-wave (Aki and Richards, 1980); Russel, Gray and Hampson (2011) derived the linear AVO reflectivity equation, \(R_{PP}^{FMR}(\theta)\), as a function of fluid factor \(f\), shear modulus \(\mu\) and density \(\rho\) along this line

\[
R_{PP}^{FMR}(\theta) = g \left( \frac{\Delta f}{f}, \frac{\Delta \mu}{\mu}, \frac{\Delta \rho}{\rho} \right) = \sum_{i=1}^{3} h_i m_i
\]

where \(h_1 = \left( 1 - \frac{\gamma_s^2}{4} \right) sec^2 \theta, h_2 = \frac{\gamma_s^2}{4} sec^2 \theta - \frac{2}{\gamma_s} \sin^2 \theta, h_3 = \frac{1}{2} - \frac{sec^2 \theta}{4}\) are the weighting coefficients and \(\{m_i\}_{i=1,3} = \left\{ \frac{\Delta f}{f}, \frac{\Delta \mu}{\mu}, \frac{\Delta \rho}{\rho} \right\}\) is the vector of fluid term, shear modulus and density contrasts between two elastic media.

Yin and Zhang (2014) proposed a fluid-matrix decoupled approximation method from the fluid term AVO inversion (Russel, Gray and Hampson, 2011) and developed another linear pre-stack inversion using AVO parameters containing four terms (the effective pore-fluid bulk modulus, \(K_f\), dry rock matrix, \(f_m\), porosity, \(\Phi\), and density, \(\rho\), reflectivity’s with their weighting coefficients, respectively). As
such, they provided the basis for estimating the seismic scale effective pore-fluid bulk modulus directly from pre-stack seismic gathers. Despite of this interesting feature, this method has limitation when used to estimate fluid and porosity for rocks that do not have good grain mineral sorting, i.e., rocks without well sorting trend.

Based on Equations (1) and (2), we have recently developed a new four parameters linear AVO inversion which addressed the limitation of the previous methods. We call this inversion method as the fluid bulk modulus inversion (fBMI) method to find a direct relationship between the fluid term, \( f \), as defined in Equation (3) and the fluid bulk modulus, \( K_f \), using the Biot poroelastic theory (Biot, 1956) and the Gassmann fluid substitution relationship (Gassmann, 1951). Using this relationship, a new linear AVO approximation has been derived that allows re-parameterization of the Biot-Gassmann fluid factor with the pore-fluid bulk modulus, \( K_f \) in the form of:

\[ R_{PP}^{fBMI}(\theta) = g \left( \frac{\Delta K_f}{K_f}, \frac{\Delta \rho}{\rho}, \frac{\Delta \mu}{\mu}, \frac{\Delta \varepsilon}{\varepsilon} \right) = \sum_{i=1}^{4} h_i m_i \]  

(3)

Where \( h_1 = \left( 1 - \frac{\varphi^2}{\varphi^2} \right) \frac{\sec^2 \theta}{4}, h_2 = \left( 1 - \frac{\varphi^2}{\varphi^2} \right) \frac{\sec^2 \theta}{4}, h_3 = \frac{\varphi^2}{4} \sec^2 \theta - \frac{\varphi^2}{2} \sin^2 \theta, \) \( h_4 = \frac{1}{2} - \frac{\sec^2 \theta}{4} \) are the weighting coefficients; and \( \{ m_i \}_{i=1,4} = \left( \frac{\Delta K_f}{K_f}, \frac{\Delta G}{G}, \frac{\Delta \mu}{\mu}, \frac{\Delta \varepsilon}{\varepsilon} \right) \), \( K_f \) is the fluid bulk modulus, \( \mu \) the shear modulus, \( G \) the gain function as defined by Han and Batzle (2003) and \( \rho \) the bulk density.

Equation (5) can be expressed as an algebra linear equation system

\[ d(t, \theta) = G(t, \theta) m(t). \]  

(4)

where \( d(t, \theta) = w(t, \theta) \ast R_{PP}^{fBMI}(t, \theta) \) is the data vector of angle stack or gather; \( G(t, \theta) \) is the kernel matrix consisting of wavelet coefficient, AVO linear parameters and derivative coefficient matrices; and \( m = [\ln K_f, \ln G, \ln \mu, \ln \rho] \) is the model vector of fluid bulk modulus, Gain function, shear modulus and density values.

The solution of Equation (4) poses, however, several fundamental issues due to non-linearity, non-uniqueness and instability. To address these issues, we use the unconstrained, regularized equations with mixed \( L_2 \) applied on the data space and \( L_1 \) norm applied on the model space (Goldstein and Osher, 2008). The corresponding objective function for this optimization procedure is given by

\[ J(m) = \frac{\mu}{2} \| d - G(m) \|^2_2 + \sum_{i=1}^{4} \frac{\varepsilon_{L_2,i}}{2} \| R_{L_2,i}(d) - R_{L_2,i}(G(m)) \|^2_2 + \sum_{i=1}^{4} \| R_{L_1,i}(m - m_0) \|^2_1 \]  

(5)

where \( \mu, \varepsilon \) are the damping factors used to weight the different \( L_2 \) regularization terms of the cost function; \( R_{L_1,i} \) and \( R_{L_2,i} \) are \( L_1 \) and \( L_2 \) regularization terms for each model \( m_i \); \( m_0 \) is the initial model vector which can be taken zeros for relative inversion purposes. The solution of Equation (5) gives inverted values of fluid bulk modulus \( K_f \), \( \mu \) the shear modulus, \( G \) the gain function and \( \rho \) the bulk density from seismic data.

Real data application in Malay basin

The fBMI is applied on the three (mid, near and far) seismic angle stacks in a field in Malay basin. Prior to the use of fBMI result, fluid bulk modulus analysis at the well location is conducted in order to specify a heuristic cut-off of fluid bulk modulus values used later to calibrate the BMI result to the well data. The aim of this well calibration to provide realistic threshold of values of fluid bulk modulus applicable to indicate brine or hydrocarbon.

The well panel analysis for four wells located across the study area is exemplary shown in Figure 1. By closely inspecting the water saturation and fluid bulk modulus curves in this figure, it can be observed that the brine fluid shows overall 2.3 GPa or larger. From this observation it could comfortably be
assumed that any fluid bulk modulus value below 2.3 GPa should indicate hydrocarbon presence with different hydrocarbon saturation degree. However, in order to provide a safe demarcation of fluid bulk modulus value which can be used to distinguish between brine and hydrocarbon, a fluid bulk modulus value threshold of 2.1 GPa is heuristically taken based on the visual inspection between water saturation and fluid bulk modulus curves in the calibration well panels. The quantitative relationship between saturation and fluid bulk modulus values are assumed following properties of fluid described by Batzle and Wang (1992), but not investigated further in this study.

Figure 1 Comparison analysis of water saturation (blue curve) and fluid bulk modulus (red curve) of well logs in a Brown field of Malay basin. In each panel the blue curve indicates the water saturation from 1 to 0.1 (left to right direction), red curve shows the fluid bulk modulus from 1.3 to 2.3 (left to right direction) and yellow panel indicates the coal presence (displayed with black strips).

Figure 2 a) Fluid bulk modulus values resulting from fluid bulk modulus inversion extracted on the horizon representing the top of target reservoir stratigraphic unit. b) Results of litho-fluid facies classification using ML-based rock physics hydrocarbon classifier method plotted on the same surface as figure 10a.

Figure 2a shows an example of the fluid bulk modulus volume extracted along a horizon representing the top of target reservoir. Blue color indicates bulk modulus value larger than 2.1 GPa, the yellow-reddish color shows the bulk modulus values smaller and equal than 2.1 GPa. The presence of low fluid bulk modulus values in the north-western and mid-western parts are proven oil and gas fields in the area. As comparison, Figure 3b depicts the results of fluid classification using the more comprehensive machine learning based rock physics-based hydrocarbon classifier (RPHC) method extracted along the same target horizon as for the Figure 3a. In this figure, blue color shows water-bearing zone and green red indicates hydrocarbon bearing zones. Closely inspection of Figure 3a and 3b shows that the indicated potential location of hydrocarbon presence resulting from both methods are similar despite of
completely different ways of extracting fluid relevant quantitative values from seismic data. This confirms that the new inversion method for direct calculation of fluid bulk modulus has potential application as fully data-driven direct hydrocarbon indicator.

The use of fBMI opens a great opportunity to conduct hydrocarbon upside potential inventory using seismic data. As theoretically described in the previous section, the main limitation of the BMI is due to the highly linearized AVO equation and the bulk modulus value sparsity. This limitation requires proper and careful preparation of the input seismic data which can guarantee the preservation of fluid response in the seismic amplitude to avoid misleading interpretation of the low bulk modulus values.

Conclusions

By using poroelastic theory, we have successfully extended the linear AVO reflectivity equation in such a way that pore fluid bulk modulus, shear modulus, porosity parameter and density can be estimated using standard AVO least-squares extraction. The new inversion technique allows calculating fluid related parameter from seismic angle stack or gather that can be used as direct hydrocarbon indicator. The application of this technique on real data set in Malay basin shows low fluid bulk modulus values, i.e., $K_f \leq 2.1 \text{ GPa}$ at the north-western region which seems to be consistent with the known production zone in those areas. The hydrocarbon prospect assessment using machine learning based rock physics hydrocarbon classification indicate similar area with a high probability of hydrocarbon presence. However, the fluid bulk modulus inversion provides a quantitative measure in terms of fluid parameter in a more robust and straightforward manner. Further investigation is necessary to address highly linearized AVO equation and non-uniqueness to quantify and reduce uncertainty in the interpretation of fluid bulk modulus inversion result.

Acknowledgements

We thank the management of PETRONAS for allowing us to publish this work and acknowledge the input of many colleagues who have contributed to the PETRONAS GeoImaging research.

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