Predicting the microseismic response in a naturally fractured shale reservoir using a discrete fracture network model

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Summary

The goal of this study is to characterise a shale gas reservoir using a geomechanical facies approach and to improve our understanding of the controls that natural fractures play in microseismicity. Each geomechanical facies is used to populate a distinct element model. The model predicts the microsiesmic response of natural fractures to a change in the stress regime that is associated with hydraulic stimulation. The modelling approach consists of creating a discrete fracture network (DFN), then incorporating the DFN into a deformable matrix based on elastic properties of the rock. The stress regime in the model is perturbed and a simulated microsiesmic response is created in order to assess where and how fracturing occurs. The simulated response is compared to the actual microseismic spatial distribution, and the model is iteratively refined. Interpretation of the results enables understanding of the potential relationship between natural fractures and geomechanical parameters and how they behave under different stress regimes. A case study of a shale gas reservoir is provided and conclusions about the location of fracture enhanced permeability are made.

Introduction

Microsiesmic monitoring of hydraulic fracture stimulation provides hypocenter locations of events that in many cases correspond to slip on pre-existing fractures in the earth. In complex fracture geometries, the microsiesmic response is strongly controlled by the natural fracture network (Cipolla et al., 2012). When the strength of the fracture is exceeded by the driving stress, slip occurs and seismic waves are emitted. Large-scale stress perturbations may result from fluid leakof into the fracture network or stress shedding from propogating a hydraulic fracture (Busetti et al., 2014; Rutledge et al., 2004). These large-scale stress perturabtions are used as a base assumption to asses how the rockmass may respond to a change in the stress regime. Rather than the conventional workflow of analysing how a microsiesmic distribution predicts information about the natural fracture network, a predicted microsiesmic response is generated from a given fracture network. The geomechanical modelling provides insights into the control of input paramters on the microsiesmic response.

Theory and Method

The geomechanical facies boundaries are identified based on changes of fracture density, stiffness contrasts and microseismic event changes. Fracture density curves, are calculated from a binned summation of fracture intersections along the well bore. This data may be supplied from core or image log analysis. TOC and permeability curves are also used to infer the occurrence of natural fractures (Ding et al., 2012 and Grieser et al., 2007). Elastic paramteres such as Young's modulus and Poisson's ratio are used independently as well as combined into a brittleness index (Rickman, 2008). Brittleness indices are also calculated based on mineralogical composition (Jarvie, 2007; Wang and Gale, 2009). While debate continues on the effectiveness and suitability of brittleness indices for predicting fracture stimulation response (Herwanger et al., 2015), this study finds them to be effective as indicators to determine geomechanical facies boundaries. The DFN is calculated as statistical distributions of fracture size, density and orientation within each facies.

The interpreted geomechanical facies are then modelled using the distinct element model software package 3DEC (Itasca, 2013) that allows for the slip and stresses along the fractures and matrix to be resolved. By resolving the slip directions and magnitudes across the individual fracture faces, a simulated microseismic response is obtained by calculating the moment tesor

$$M = \begin{bmatrix} M_{11} & M_{12} & M_{13} \\ M_{21} & M_{22} & M_{23} \\ M_{31} & M_{32} & M_{33} \end{bmatrix}$$

Where moment tensor components are calculated as (Aki and Richards, 2002)

$$M_{pq} = \iint_{\Sigma} m_{pq}\, d\Sigma = \iint_{\Sigma} [u_i] v_j c_{ijpq}\, d\Sigma$$

Where p is force couple direction, q is the force couple arm direction, Σ is the fault plane, u_i is slip component, v_j is the normal component to the fracture and c_{ijpq} is the elastic constant. It follows that $[u_i]v_j c_{ijpq}$ is the strength of the force couple and has dimensions of moment per unit area.

The locations, magnitudes and radii of the events are compared to the original data. By varying model parameters such as stress direction and magnitude, a match to the observed data can be made. A sensitivity analysis is then performed which highlights the controlling mechanisms of the fractures under the different geomechanical facies.

Results

Core, log and microseismic data was acquired in a shale reservoir. A summary of the data is shown in Figure 1 with the lithology, geomechanical properties and microseismic response.

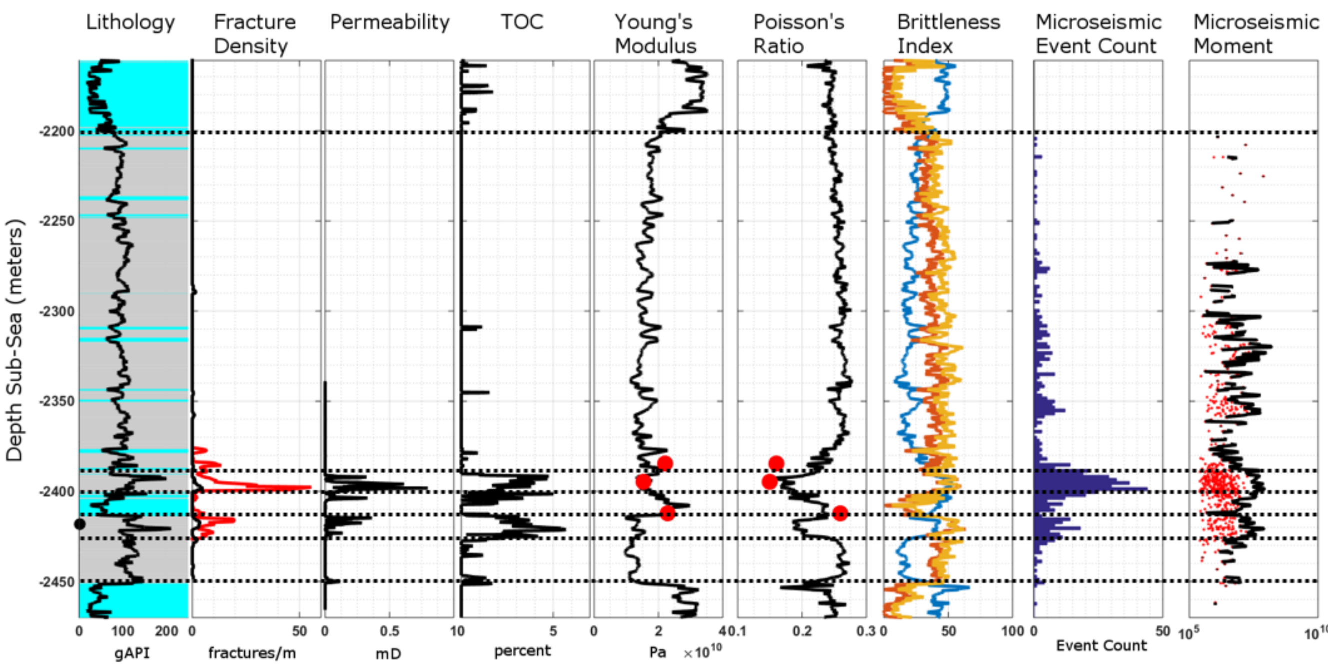

Figure 1 – Illustration of study geomechanical facies boundaries. From the left track to right: 1. Lithology where cyan is carbonate, gray is shale, black line is gamma ray and circle marker is the treatment depth. 2. Fracture densities where the black line is from the image log and red line is from core observations. 3. Permeability NMR log. 4. TOC content 5. Young's modulus corrected to static values from core samples marked in red. 6. Poisson's ratio corrected to static values from core samples marked in red. 7. Brittleness index showing $BI_{Rickman}$ (blue), BI_{Jarvie} (red) and BI_{Wang} (orange). 8. Observed microseismic events binned by depth. 9. Moments of each microseismic event in red and cumulative moment in black. Geomechanical facies boundaries are shown as black dashed horizontal lines.

Seven geomechanical stratigraphic units are interpreted based on changes in rock properties and fracturing behaviour. Contrasts in the brittleness index based on both mineralogy and elastic modulii prove to be effective indicators of geomechanical facies boudaries.

Naturally fractured zones occur in the shale lithology from -2380 to -2400 meters and -2414 to -2430 meters sub-sea. These zones concentrate microsiesmicity associated with the hydraulic stimulation. Within the studied well, naturally fractured zones are found in zones with high TOC content. These zones also exhibit higher permeability, suggesting that formation permeability is controlled by the natural fracture distribution.

It was found that large perturbations in fluid pressure from fluid leakoff result in the greatest cumulative moment and displacement of natural fractures. A parameters that is particularly significant for cumulative moment is the friction angle; this sensitivity indicates that polished slickenline slip faces or bedding parallel fractures may contribute to larger cumulative moments.

Finally, it is observed that in this case the microseismic distribution is controlled by the natural fracture network, indicating that rockmass strength and preferential failure is likely to be controlled by the presence and abundance of natural fractures within the shale reservoir. Furthermore, when logging core for natural fractures, it was found that coring and handling induced fractures could be used as a proxy for weak areas in the rockmass that were likely to respond to hydraulic stimulation.

Conclusions

By modelling a series of geomechanical facies in different stress regimes, the expected microsiesmic response can help inform decisions about the control on deformation within the reservoir. These models can be used as a framework to understand the microseismicity associated with stress perturbations surrounding hydraulic fracture treatments. This forward modelling approach can also be used to determine the sensitivity of deformation to various geomechanical parameters in different facies.

Because the microsiesmic distribution is controlled by the presence of natural fracutres, events highlight zones of fractured rock. The events also congregate in zones of weak rock where induced fractures are most prevelant. These zones are likely to be contributing to fluid flow and may define fluid pathways within the reservoir (Williams-Stroud, et al., 2012). This microseismic prediction approach can be used as a guide to identifying natural fracture zones that will best respond to hydrraulic stimulation both laterally as well as vertically through the reservoir.

Acknowledgements

Tight Oil Consortium

Microsiesmic Industry Consortium

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