Constraining models of fractured reservoirs using seismic anisotropy maps, for improved reservoir performance and prediction

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Summary

Traditionally, reservoir fracture models are matched to only primary fracture data at well locations, and thus suffer from increasing uncertainty away from wells. In this work the discrete fracture network (DFN) approach is used to show how sub-seismic fracture realizations can also be constrained to seismic data. This methodology provides a route by which the uncertainty in the distribution of reservoir permeability and storage can be significantly reduced, and helps make forward predictions from the simulator more accurate. It also provides a natural way of extracting value from seismic anisotropy measurements and using them to quantitatively control the reservoir model for field development and management.

Introduction

Fractures found in reservoirs can have a wide range of scales, from very small-scale microcracks to formation-scale through-going conduits. These can act as both permeable pathways to fluid migration and also as significant storage. As more low permeability reservoirs, particularly carbonate systems, are exploited, the need to quantitatively characterize the distribution and properties of fractures within the subsurface increases. A key issue is the way in which reservoir models are populated, and parameters such as transmissivities, porosity, fracture geometry and connectivity remain difficult to input accurately into the flow model using the dual porosity approach (MacBeth and Pickup 2002). Without properly assigned parameters, the number of acceptable scenarios and hence the spread of models increases, making production forecasting a risky business. Engineers therefore desperately need additional information on fractures, particularly in reservoirs where sub-seismic fractures dominate flow.

Here, we focus on the prediction of the spatial distribution and geometry of these fluid-conductive fractures and their integration within useful reservoir models as a way of reducing the development uncertainty for reservoirs. This is achieved by working with a fracture generator that has the potential to honor the well data, geological data, dynamic well test data, and picked faults, and also maps of seismic anisotropy intensity and orientation. These seismic data provide aerial distributions of both fracture intensity and orientation whilst the borehole images and core data provide harder 1D depth snapshots, and finally the well tests giving the local permeability structure. In an almost parallel way to seismic history matching, it is hoped that by combining the information in a procedure that constrains to all available information, the requisite fracture geometry can be better defined.

Seismic characterization of natural fractures

There are many excellent examples of seismic anisotropy measurements for P-P, P-S and S-S data on a field-wide basis (for example, Lynn et al., 1999; Gaiser et al., 2002; Hitchings and Potters 2002). Indeed, the technique is now accepted as having a proven track record of adding value in reservoir characterization. However seismic anisotropy maps need to be more than a supplementary qualitative guide to well planning, the information needs to be integrated more effectively at a quantitative level into the reservoir model building workflow. Here we illustrate how this might be accomplished by using two very different seismic examples and a fracture generator.

Example 1: This example is taken from a land-based wide azimuthal 3D P-wave data from the Yellow River delta in East China (Li et al. 2003). The area is bounded to the west by the Yellow River plain and to the east by the Yellow Sea. Most of the area heavily faulted, with the target being a fractured mud-rock located at the depth of about 3000m. Oil production in the area mainly relies on knowing fracture information. Final fracture maps for the test area are made from the interval travel time, and the patterns compare reasonably well with the fault patterns in the study area. We can also see that along the faults the fracture intensity seems to increase. The dominant fracture orientation is N40°E and there is a near-orthogonal direction at N30°W or N15O°E, which may be interpreted as the secondary fracture set. These are consistent with the regional stress field. Figure 1 shows the full-field results, and further fracture porosity and permeability maps may be inferred from these results for input to reservoir modeling.

Example 2: This example is taken from the Rulison field, Piacence basin, Colorado. The dataset was previously studied by Lynn et al. (1999). The target interval is at the gas-saturated Mesaverde (5000–7000’ depth), consisting of a finely layered sequence of sands, silts and shales with significant lateral stratigraphic changes. There is low matrix porosity and permeability, and production and the presence
of commercial pay is limited to areas of strong fracture intensity. Major faulting lies along the N30°W direction, which also parallels the structural trend. The 3D P-P data volumes are processed by using the P-P AVOA. Fracture intensities appear correlate with the picked seismic faults.

**Figure 1.** Fault map for Yellow River dataset, with the corresponding time structure.

**Fracture 2.** Seismic anisotropy and faults corresponding to the Yellow River data in Figure 1.

**The discrete fracture network (DFN) approach**

The *DFN* approach was born out of recognition that systems dominated by discrete features are poorly represented by conventional dual continuum approaches. *DFN* model therefore seek to explicitly represent fractures or other discrete geometries seen within the rockmass as 2D elements having both geometrical and hydraulic properties. We aim to find a way of generating fracture network realizations and hence permeability structure that are guided by stochastic processes honoring both hard and soft data rather than a fixed deterministic model as in previous cases. Models are formed by placing discrete elements in both a deterministic or stochastic sense, so as to match all available data (Dershowitz et al. 1998). *DFN* models are thought to provide a better match connectivity and scale-dependent heterogeneity, properties critical to accurately capturing the hydraulic behavior of the reservoir.

**Figure 3.** Structure map of the Top Mesaverde, a gas producing interval in the Rulison field, and corresponding fault picks at that level.

**Figure 4.** Seismic anisotropy and faults for the Rulison data, determined using P-P AVOA technique.

*DFN* models are increasingly being seen as the most effective way to model fractured reservoirs where complex geometries result in unusual and often highly directional
flow regimes. It is their ability to accurately capture the complex spatial distributions and connectivity of fractured reservoirs that make them more effective than traditional continuum methods. The model is particularly useful as it can be integrated with available well-based fracture data by comparing the geometry of the intersected fractures with real core or image based fracture data. Another of the strengths of the DFN approach is its ability to capture both geological and dynamic data within the same model. This can be used for forward modelling of heterogeneous reservoirs to identify the likely pressure responses that might be observed. The use of the pressure derivative from pressure transient tests has been shown to be a diagnostic tool for understanding the nature of a fracture network intersected by a well (Wei et al. 1998). In particular, the DFN modelling approach allows the static fracture model to be converted into a flow grid that allows testing through the simulation of available pressure transient tests. The upscaling of fracture permeabilities to directional grid-scale permeabilities provides a robust method of deriving conditional hydraulic values that accurately capture the anisotropy and heterogeneity of the fractured reservoir.

Methodology and results

The above approach is used in a workflow that helps define a fracture network for two different test seismic datasets. It is hoped that the seismic imaging route to reservoir fracture model can help to minimise the inter-well uncertainty whilst the use of DFN technology helps to accurately condition the model against static and dynamic data. The flow divides into two main areas:

1. **Static validation** - the data are pre-processed and prepared to obtain seismic intensity and orientation maps. This stage depends on the type of data (P-P, P-S or S-S) and data quality. These seismic intensity and orientation maps are converted into appropriate fracture parameters using fundamental rock physics relations, preferably calibrated by laboratory measurement. If available, vertically zoned seismic impedance tied to individual well locations may also be used to help condition any vertical distribution of fracturing. The geological context must be defined (faults, folds, and stratigraphy). After set up, fractures are generated, constrained to the seismic data in a least-squares sense.

2. **Dynamic validation** - ideally, a dynamic validation of the fracture model based on assessment of hydraulic connectivity and flow units; well tests and other data. This will locally refine the models for transfer of the output into an eclipse reservoir model for field-wide simulation. The ability to perform dynamic simulations through discrete fracture network models has been shown to be an unparalleled way to help unravel the complexity of how fractures connect away from the well. The pressure derivative taken from well tests has certain diagnostic properties that can be used to help resolve such properties as fracture connectivity, length scale and permeability.

**Figure 1.** General workflow for seismically-constrained fracture generation based on the DFN technique.

**Figure 5.** Output from the DFN procedure, to produce a fracture network ready for calibration with dynamic data. for the Yellow River dataset.
Constraining fracture models for improved predictability

Figure 6. DFN model for the Rulison dataset. This model has been analyzed for connectivity, with clusters of more than 5 fractures colored

Discussion and conclusions

Over the past ten years, a wide range of innovative techniques have been developed for mapping the intensity and orientation of fractures using 3D P-wave, converted-wave and S-wave data. These seismic attributes can now be used as the primary input for the advanced fracture modelling tools. In this paper, we have presented some results of Discrete Fracture Network (DFN) modeling for fractured reservoirs, a technique that lends itself naturally to integration with seismic data. Results of successful application on two quite different datasets suggest that the technique holds promise. Whilst the determination of meaningful fracture attributes from seismic data is not a trivial process and the route is not yet without uncertainty, the seismic–fracture model methodology has provided a way of addressing the interwell uncertainty present in most fractured reservoir models. This means that there is the potential for different well configurations and completion strategies to be modelled to improve development planning before drilling. Other geometric issues that could be resolved using the DFN approach are injector-producer short circuits, prediction of early water breakthroughs and also the planning of enhanced recovery methods.

It should be emphasized that for the technique proposed here to have the maximum impact, the reservoir conceptual model should suggest that the seismic attributes are strongly linked to the features that dominate reservoir permeability. Thus, this technique lends itself best to carbonate reservoirs with a thickness of around 40m or greater (for example, Al-Hawas et al. 2003). Ideally they would be single layers or multiple layers with similar mechanical properties. There are other items that require attention before this workflow can be established with confidence. The conversion of seismic anisotropy intensity and orientation into true fracture intensity and orientation represents a major theoretical hurdle not acknowledged to date. Also required is an assessment of the balance between seismic aerial content and borehole 1D data.

References


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