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Natural Fracture Prediction: A Multiscale Integration of Seismic Data, Image Logs and Numerical Forward Modelling

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Summary

Natural fracture networks are commonly observed in tight carbonate and chalk reservoirs and are believed to have significant impact on the effective permeability and potential fluid flow behavior. For instance, production from chalk fields in the North Sea is believed to be aided by the presence of natural fracture systems. Apart from enhancing production, fractures can also result in channelized fluid flow and early water break-through. In this study, we propose a multiscale and data-driven workflow of automated fault extraction, image log interpretation and both inverse and forward modelling, to characterize and quantify potential inter-well fracture network geometries and densities. The workflow is exemplified on the Ekofisk chalk field situated in the Norwegian North Sea. The seismic and well data show that the Ekofisk fault and fracture system forms a connected system, which can be subdivided into four main structural orientations. Inverse modeling suggests that the orientations of the fracture/fault system can be explained by three separate normal faulting events. By implementing the structural data into a forward simulation, we characterize the potential inter-well fracture/fault network highlighting that fractures occur in clustered zones which follow the four main observed orientations.

Introduction

Natural fractures play an increasingly important role in estimating the effective permeability in tight or low permeability rocks. Therefore, predicting the geometry, location and intensity of these structural elements has become an integral component of characterizing reservoirs with low matrix permeabilities. This type of reservoir characterization often considers a multitude of scales and datasets. The geometry and distribution of large-scale shear fractures (10's to 100's m) such as faults are often categorized and mapped using seismic data. The geometry and distribution of smaller discontinuities (cm's to m's) such as extension fractures (joints) generally fall below the seismic resolution and can therefore only be detected using image logs or core data from wells. However, well-centric data usually provides a 1D perspective into a 3D problem. Hence, predicting the distribution of sub-seismic features in a 3D volume requires interpolation of the well data. Recent studies have shown that linear elastic forward modelling of geologically constrained data can help in predicting and extrapolating possible fracture intensity fields, using numerically derived stress and strain fields (Maerten & Maerten, 2006; Maerten et al., 2016).
In this study we expand this numerical workflow (Maerten et al., 2016) and propose a multiscale fracture prediction methodology which combines automated fault extraction, image log interpretation, paleo-stress reconstruction and linear elastic forward modelling to predict and model possible inter-well fracture network characteristics, such as fracture density and orientations. This workflow is exemplified on the Ekofisk chalk reservoir.

Methodology and data used

In the present work, we focus on the southern part of the Ekofisk field (Fig. 1a), i.e. the region south of the salt dome center and the seismic obscured area (SOA). A multiscale workflow for the characterization and interpretation of larger fracture/fault systems has been developed using 4D seismic survey data and density image logs from horizontal wells. From the original seismic volume an initial seismic fault cube is extracted using five subsequent volume attributes which highlight seismic discontinuities. The fault cube is then used to automatically extract a 3D fault model (Figs. 1b&c) (Boe, 2012; Bounaim et al., 2013), while the fracture data is acquired by interpreting density image logs. The proposed modelling approach uses iBEM3D (Maerten et al., 2016), which combines both inverse and forward modelling to identify possible paleo-stress regimes and model/predict possible inter-well fracture network densities, using the 3D fault model and interpreted fracture data and assuming deformation following Linear Elastic Fracture Mechanics. In the proposed modelling workflow, the calculated fracture densities are calibrated by the measured fracture intensities acquired from the provided image log data.

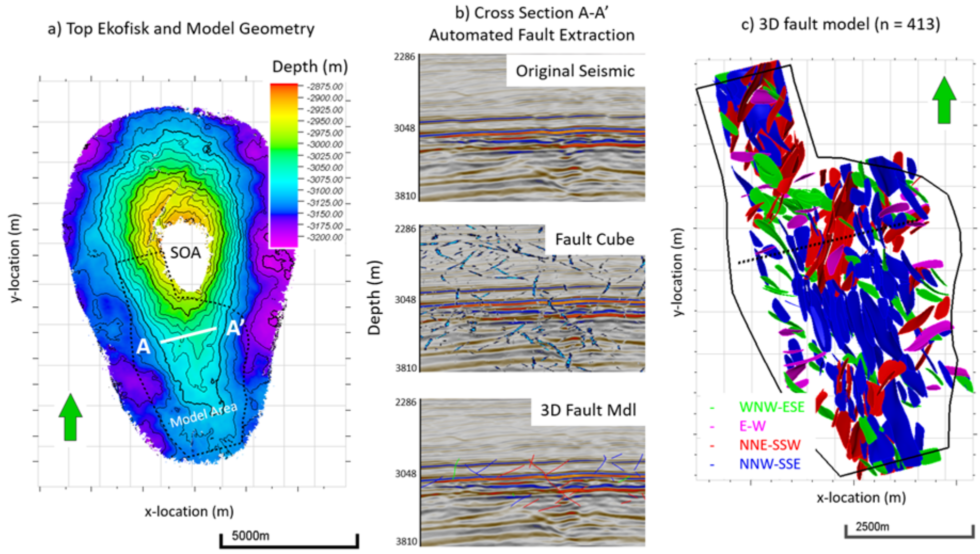

Figure 1: *a) Model geometry and top Ekofisk horizon, which highlights the dome structure of the Ekofisk field. b) Cross section A-A', depicting the original seismic, the extracted fault cube and the faults included in the fault model. c) The 3D fault model.*

Results: Structural analysis of the seismic and image log data

The 3D fault model comprises four main fault orientations, namely: WNW-ESE, E-W, NNE-SSW and NNW-SSE, which mostly show low fault throw (Figs. 1b&c). Some of the larger faults show normal behaviour and throw up to 20m. The NNW-SSE faults are aligned parallel to the hinge line of the dome structure, and mainly occur in the hinge zone of the dome (Figs. 1a & c). The WNW-ESE and NNE-SSW fault groups occur more in clustered zones, which was also observed in previous work (Toublanc et al., 2005). Finally, the extracted fault model indicates that in locations where either NNE-SSW and WNW-ESE faults are present, less hinge faults are observed (Fig. 1c), which implies that both fault groups where already present during hinge faulting.

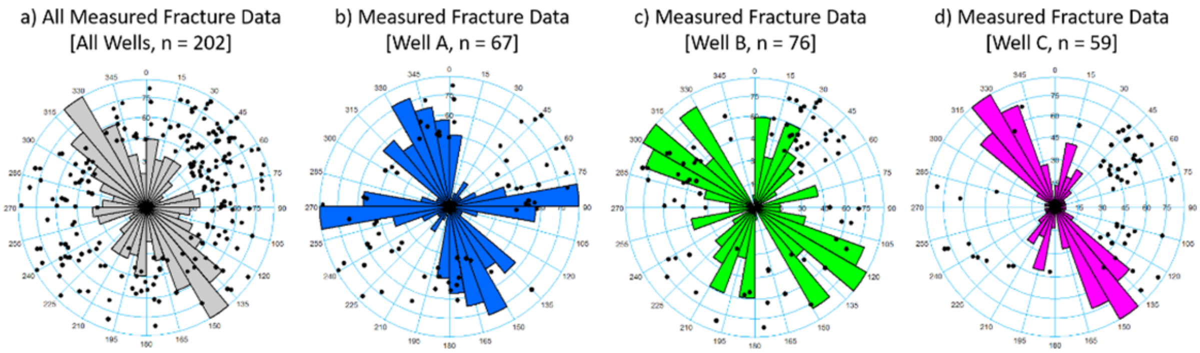

Figure 2: *a) Structural data from the wells incorporated in the project. b-d) The structural data filtered by each incorporated well respectively.*

The image log interpretation results show the same four structural groups, indicating that the observed faults and fractures are structurally related and have most likely developed as a response to similar tectonic events (Fig. 2).

Results: Integrating the structural data into a forward simulation

The inverse calculations done on the interpreted fracture data (mechanical fracture types: mode II < 75^0, mode I ≥ 75^0) (assuming Andersonian faulting), show that the data can be explained by three subsequent normal faulting events, namely (Figs 3 a, b & c respectively):

1) WNW-ESE Normal Faulting $\sigma_H = 113°, (\sigma_2 - \sigma_3)/(\sigma_1 - \sigma_3) = 0.72$, TR* = Normal
2) NNE-SSW Normal Faulting $\sigma_H = 20°, (\sigma_2 - \sigma_3)/(\sigma_1 - \sigma_3) = 0.84$, TR = Normal
3) NNW-SSE Normal Faulting $\sigma_H = 157°, (\sigma_2 - \sigma_3)/(\sigma_1 - \sigma_3) = 0.46$, TR = Normal

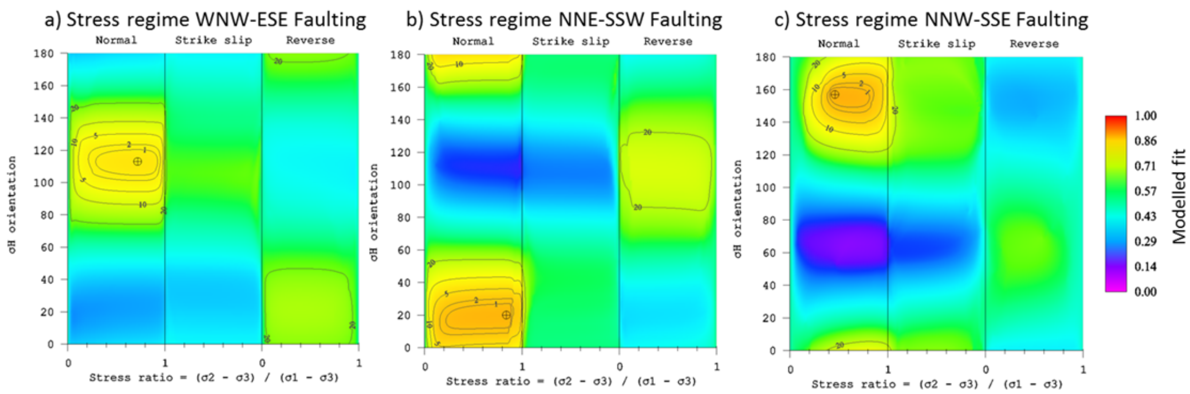

Figure 3: a-c) *Inversely calculated stress regimes for each subsequent tectonic event, respectively.*

For our forward modelling approach, we activate each fault group for each respective tectonic event and keep them activated throughout the subsequent modelling steps, at which the order of faulting is derived from the structural and literature analysis (Fig. 4) (Toublanc et al., 2005). The derived stress fields show localization and reduction of the differential stresses surrounding each activated fault tip and fault plane respectively (Fig. 4). *(Tectonic Regime).

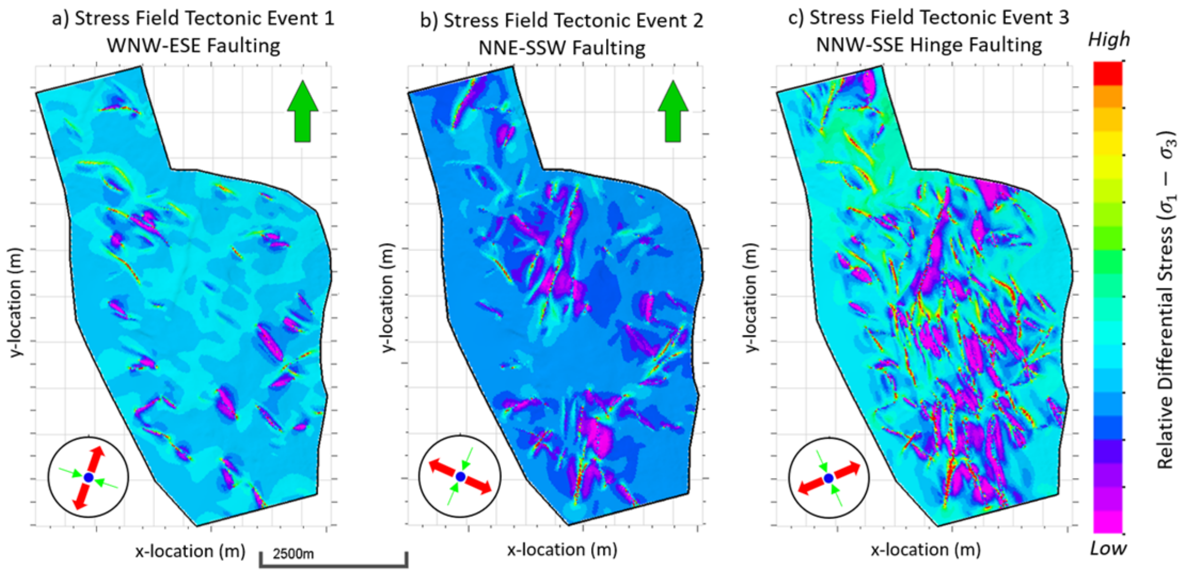

Figure 4: *a-c) The modelled local differential stress field for each subsequent tectonic event respectively. The applied stress regimes are inversely calculated using the fracture and fault data.*

The fracture density results can explain ~90% of the fractures observed in the wells (included in the simulation), and the predicted intensity field shows clustered behaviour surrounding faults (Fig. 5a). Since faults are believed to impact the effective reservoir permeability to a great extend (Toublanc et al., 2005), the extracted fault cubes are included in the calibrated fracture intensity model (Figs. 5b & c). The calculated intensity cube (Fault Intensity + Fracture Intensity) shows that high intensity fracturing and faulting occurs in clustered zones (Fig. 5c), and assuming that fractures enhance the effective permeability, fluid flow will most likely be channelled along these high intensity zones.

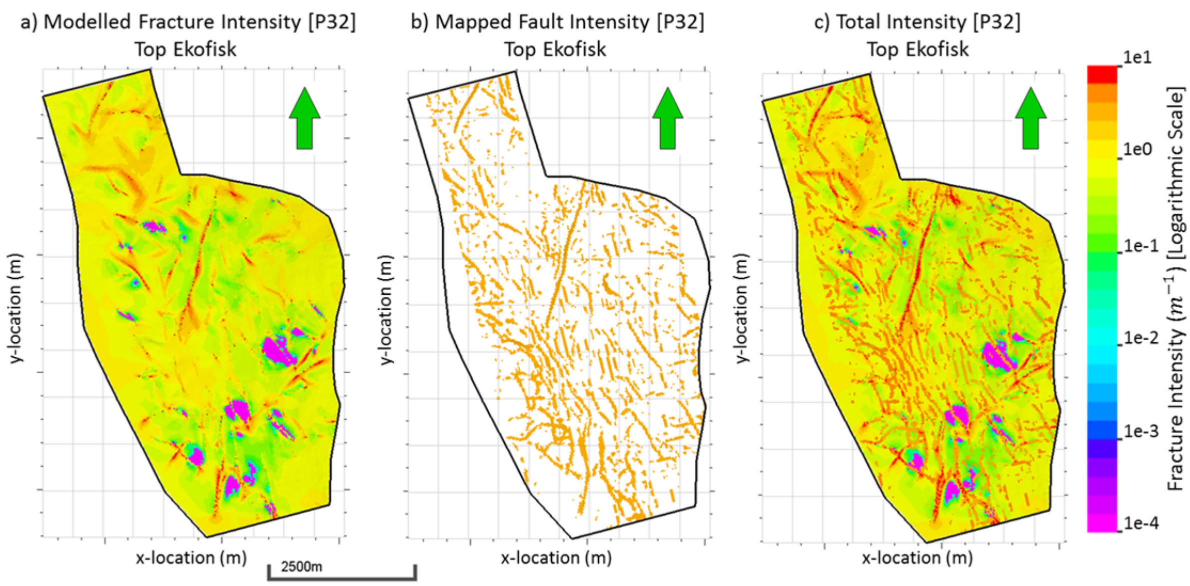

Figure 5: *a) The modelled and calibrated fracture intensity. b) Mapped fault intensity (assigned P32 = 3.28 [m^{-1}]). c) Total fracture and fault intensity.*

Conclusions

This study implements a multiscale approach of automated fault detection and extraction, image log interpretation and numerical modelling, to model and predict possible inter-well fracture network densities concerning the southern Ekofisk field. Firstly, the acquired fault model and interpreted fracture data show similar results and indicate four different fault and fracture orientations, namely: 1) WNW-ESE Group, 2) E-W Group, 3) NNE-SSW Group and 4) NNW-SSE Group. Furthermore, the performed inversion analysis suggest that these four different orientations can be explained by three subsequent normal faulting events. The forward modelling results highlight that natural fractures and faults occur in high intensity clusters, which form a connected network. Moreover, the numerical results show a close correlation with the data interpreted from the three provided image logs. Therefore, the multiscale inverse and forward modelling approach presented here, highlights a quantitative way of understanding and forecasting secondary permeability changes in producing chalk reservoirs.

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