Seismically Driven Fractured Reservoir Characterization Using an Integrated Approach - Joanne Field, UK

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SUMMARY

The Joanne Field is an Upper Cretaceous Chalk reservoir in the UK sector of the Central North Sea. Over the production life of the field it has become increasingly apparent that the presence of fracturing has a significant impact upon the efficacy of the Joanne reservoir. Standard techniques for identification and quantification of the fracture networks across the Joanne Field have been severely affected by the lack of primary fracture identification data from the original wells, consisting of only 3 oriented cores and one OBMI image. Because of these limitations, the Continuous Fracture Modeling (CFM) neural network technique has been applied to this field in order to compare the limited fracture identification data that is available against key high resolution seismic Driver attributes. Available core information and a recorded Mudloss Log acquired during the drilling of the M8 production well were used as quantitative fracture identifier datasets for use in the CFM modelling exercise. Key primary output from the CFM model consists of a series of seismically driven geocellular volumes with the primary results being a Fracture Intensity volume and a coincident Permeability volume.
Introduction

Joanne Field is located on the UKCS approximately 270 kilometres east of Aberdeen on a salt-cored four-way dip closed structure. Production comes from allochthonous chalks of the Upper Cretaceous Maastrichtian Tor Formation deposited by a series of stacked turbidite lobes originating from the northwest that cover the western and southwestern flanks of the structure. Unlike the better known chalk fields of Norway and Denmark, UK chalk accumulations suffer from a combination of generally greater depth of burial and lower overpressures resulting in significantly less matrix permeability. For this reason, fracture induced permeability enhancement is a critical determinant in separated non-commercial chalk accumulations from commercial ones.

Although there have been three vertical and fifteen deviated wellbores drilled in the Joanne Field, there have been no dedicated fracture identification logs acquired in any well and oriented cores have only been acquired in four wells. This paucity of hard data on the density, orientation, and production impact of the fracture networks across the Joanne structure has necessitated the application of the Continuous Fracture Modelling (CFM) technique to predict fracture permeability distributions to aid in the construction of detailed reservoir models for production simulation. For this study, the CFM approach combined the use of high-resolution seismic attributes, well based geological information and production based data to create a neural network derived fracture model that honours all the available data and predicts areas of fracture enhancement away from well control.

Continuous Fracture Modelling Technique

The Continuous Fracture Modelling (CFM) technique uses neural network technology to investigate and identify the primary physical properties of the reservoir being modelled that control or identify the local fracture intensity within the reservoir. These “drivers” are extracted from a population of pre- or post-stack geophysical, geological and engineering attributes to construct a supervised multidimensional learning environment for the network to create a self-consistent integrated fracture model (Ouenes 2000; Zellou and Ouenes 2001; Ouenes et al. 2004; Wong and Boerner 2004).

Joanne Chalk Field

The Joanne Chalk Field was discovered in 1981 with the drilling of the 30/7a-1 exploration wellbore that discovered hydrocarbons reservoired in Paleocene Ekofisk and Cretaceous Tor Formation chalks. This well encountered a 375 foot oil column in the Tor Formation, and subsequent drilling of the 30/7a-2 and 30/7a-3 wells confirmed the presence of a significant accumulation in the Joanne structure within a stacked series of good quality allochthonous chalk layers, the thickest and best developed being the T1 zone at the very top of the Tor interval.

Although the Joanne T1 porosity zone is significantly thinner than tuning (Brown et al. 2008), drilling of the Joanne development wells was primarily driven by seismic amplitude maps derived primarily from the Tor T1 porosity zone. However, the subsequent production histories of the wells within the field reveal that well production is significantly affected by fracture induced permeability enhancement, enough so that the best well in the field (M8) is not within the area of the best developed area of primary porosity as indicated on seismic. Unfortunately, this information was obtained well after the drilling of the development wells and as a result there were no borehole image logs or any other fracture identification logs obtained for any well within the field outline.

With the exception of well test data and well production history matching models, the only semi-quantitative data available from well control to use as a Fracture Indicator became available upon the drilling of the M8 replacement well for the original M4 well which was lost after completion. A detailed mudloss log was compiled during the drilling of this well, allowing for the construction of a profile along the wellbore describing zones of significant increase in losses, which were then assumed...
to be related to the intersection of the drill bit with open fracture networks. The mudlosses at different locations were quantified in terms of volume of fluid lost and were used to create a “Mud Loss” log which was used as the Fracture Indicator input in the CFM approach.

**CFM Modelling**

In addition to the fracture indicator at the well, the CFM approach requires “Driver Attributes” which can be separated into three major categories: geophysical (seismic), geological (rock properties), and structural (curvature, deformation (pseudo-strain)). The key drivers are the geophysical ones derived from seismic inversion, spectral imaging and volumetric curvature. Seismically constrained geocellular volumes are then constructed for each of the key geological drivers (e.g. lithology, porosity, etc.) using a neural network that provides the unique ability to constrain the geological models to a multitude of seismic attributes. The CFM approach uses all geophysical, geological and structural 3D volumes along with any identified Fracture Indicators, such as can be obtained by borehole images / core / well tests, or in the case of the Joanne Field, a “Mud Loss” log.

The 3D geocellular volumes that contain the numerous drivers are ranked against the Fracture Indicators available at the wells thus yielding a relative importance of each driver in regard to the considered Fracture Indicator. The number and identity of the driver volumes that will be input into the neural network is case specific, although it is usually somewhere in the neighbourhood of a dozen or so. Upon completion of the neural network analysis, a series of geocellular volumes are produced that detail the 3D fracture intensity distribution. The results of this fracture intensity distribution can be displayed in different ways including a Discrete Fracture Network. More importantly, the resulting fracture intensity distribution can then be transformed into a 3D permeability volume for input into standard reservoir simulation. The entire workflow is executed by using Prism Seismic software CRYSTAL and REFRACT (Figure 1).

**Joanne Field Model**

Because of its excellent signal-to-noise ratio, the 3D seismic over the Joanne Field area responded well to frequency enhancement and multiple high quality attribute extractions. A post-stack resolution enhancement available in CRYSTAL was applied to the seismic data and provided an enhanced cube used in all subsequent algorithms, including volumetric curvature, spectral imaging and inversion. Approximately 20 separate seismic attribute volumes were generated, consisting of both geometric (i.e. curvature based) and energy based attributes for fracture modelling. Figure 2
demonstrates the response of a typical curvature attribute at the Tor T1 level to the application of frequency enhancement and the illumination of lineations that match the results of fracture orientation from core obtained within the field.

**Figure 2:** Comparison of oriented core fracture and OBMI Rose Diagrams against frequency enhanced Tor T1 Dip of Maximum Similarity attribute. Inset figure is SVI Dip Curvature extracted from data prior to resolution enhancement.

**Figure 3:** Seismic attribute “drivers” with well-based Fracture Indicator (mudloss zones in the M8 wellbore).

Figure 3 shows the zones of significant mudloss as logged during the drilling of the M8 production well against a geometric based attribute (Most Negative Curvature, left panel) and a seismic energy based attribute (Total Reflection Energy, right panel). Because of the small offset of the fault zones in the area to the east of the M8 well, fault connectivity is much better imaged on the right panel than on the left.

Some of the results of the fracture modelling procedure on the Joanne Field dataset are shown in Figure 4. The primary output dataset is the mean result of a large number of stochastic realizations.
generated within the neural network comparing the geoseismic drivers against the input fracture indicators. These maps reveal that areas to the south and southwest of the current well control have indications of significantly greater fracture intensity than the areas currently targeted by well control and as such should have a greater productivity index than has been assumed until now.

Figure 4: The left panel demonstrates the resulting Fracture Intensity volume generated by the CFM approach. The right panel displays the CFM result in one layer as a Discrete Fracture Network for the Tor T1.

Conclusions

The application of the Continuous Fracture Modelling (CFM) technique to the Joanne Field has provided significant evidence that the hydrocarbon productivity of the southern and southwestern flanks of the structure had been underestimated in the initial field development. This is primarily a result of an overdependence upon seismic based primary reservoir characterization to the exclusion of local secondary fault/fracture permeability enhancement in areas remote from the current production wells.

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References


