Revealing the Natural Fracture Network of the Berai Carbonate, Kerendan Field Complex, Indonesia*

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Search and Discovery Article #20356 (2016)**
Posted July 5, 2016

*Adapted from extended abstract prepared in conjunction with oral presentation given at AAPG Geoscience Technology Workshop Characterization of Asian Hydrocarbon Reservoirs, March 31 – April 1, 2016, Bangkok, Thailand
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Abstract

The Kerendan Field Complex is a mid-sized gas field located onshore Central Kalimantan, Indonesia. The field produces from the Oligocene Berai carbonate reservoir (Figure 1), an interval recognized as naturally fractured since the early phase of the exploration of the field (Crawford and Dunham, 1983). The economic development of the gas resources present in the Berai carbonate is highly dependent on the characterization of the heterogeneity of porosity and permeability prevailing over the field. The presence of fractures introduces a high level of uncertainty in the characterization of this heterogeneity.

A detailed characterization of the origin, distribution and properties of the fractures present in the Berai carbonate reservoir was then attempted using a set of recent digital borehole image data from four wells drilled over the period 2012-2014 (Figure 1). The dataset included processed OBMI (Kerendan-6 and Kerendan-7), processed FMI-HD (Kerendan-8 well) and raw and processed OMRI (West Kerendan-1 well). Image quality was regarded in general as being good in the OBMI and OMRI data, whilst the FMI-HD images of the Kerendan-8 well were of excellent quality and provided a better resolution of the sedimentary fabric and fractures due to the tool's higher intrinsic resolution. As the image logs originated from different tools, with variable quality and resolution, a systematic hand-picking of fractures on all available logs was undertaken using IP™, and fractures were classified in one common and standardized scheme on the basis of their electrical response and continuity. The interpretation was paired and calibrated using FracaFlow™, with a series of static and dynamic indicators of fracture occurrence from various origins and scales, including core analysis (wells Kerendan-1, Kerendan-2, Kerendan-3 and West Kerendan-1), interpretation of faults from 2D seismic, drilling mud losses, and preliminary observations made on reservoir performance.

Fracture Model

A conceptual model of the distribution of natural fractures occurring within the Berai carbonate reservoir of the Kerendan Field Complex was then developed based on the principles of genetic fracture classification (Bonnet et al., 2001; Cacas et al., 2001). Two main types of fractures, distinguished primarily on the basis of their structural attributes and appearance, were interpreted to be present (Figure 2). The first fracture type consists of sub-vertical fractures which are described as small scale, bed-confined and possibly related to facies. The second fracture type consists of low-angle fractures, which appear to be better developed, crossing bed boundaries and clustered as suggested by fracture density plots. Tool resolution, fault presence and well deviation were identified as the key parameters which contribute to the imaging of fractures in the available image logs.

We interpreted the sub-vertical fractures as diffuse fractures and the low-angle fractures as fault-related fractures (Figure 3). Diffuse fractures originate from the regional geodynamic stress prevailing during early stage of burial of the reservoir. Although they are likely present over the entire field, the diffuse fractures density (< 0.5 fractures/m) and variable orientations do not provide the conditions for field scale permeability anisotropy. The impact of diffuse fractures on fluid storage and flow in the Kerendan Field Complex is therefore expected to be limited. Organized in well-defined corridors and subparallel to fault surfaces, larger fault-related fractures constitute damaged zones caused by the faults movement. When associated with seismic-scale faults, they present a higher fracture density (> 5 fractures/m) and are organized in clusters > 100 m in width. Where open and connected, those fault-related fractures have the capability to ensure lateral reservoir communication in the Kerendan Field Complex, although the permeability anisotropy will be restricted to the vicinity of faults. To date no evidence of fracture contribution has been noted from production data suggesting this network to be inactive.

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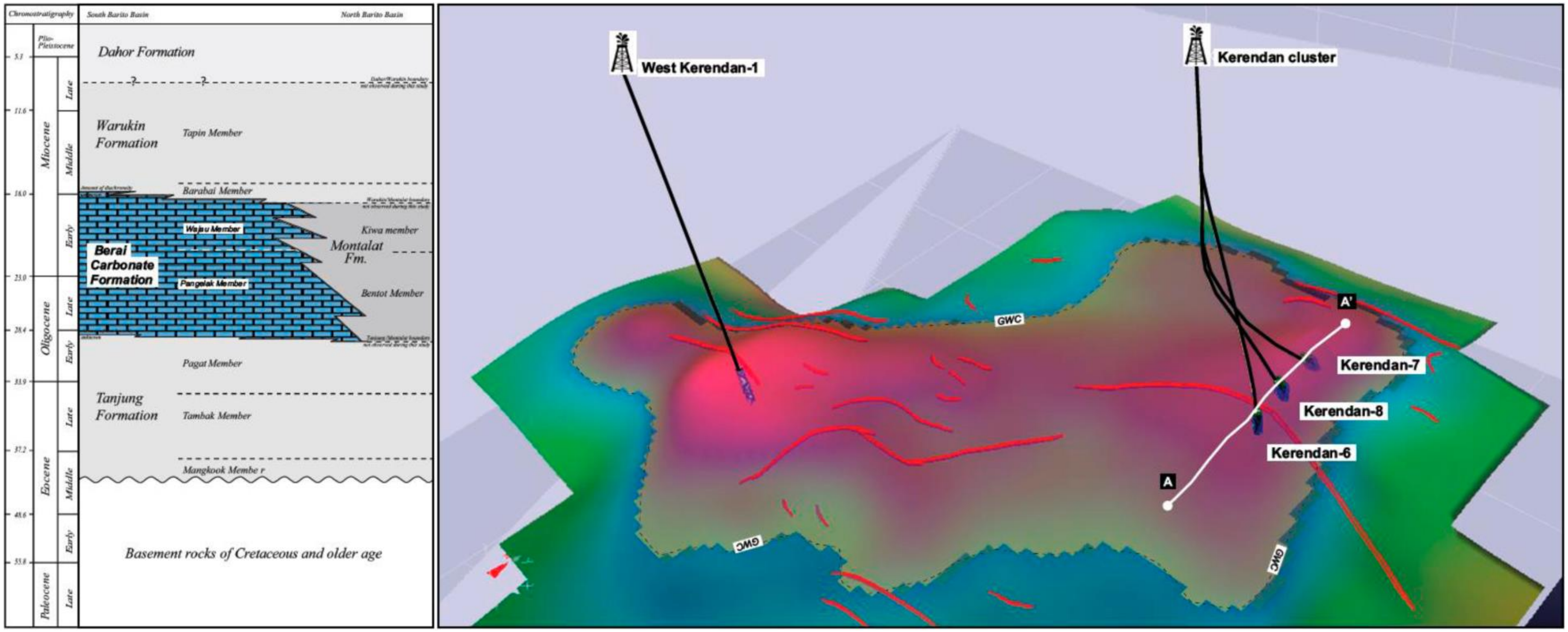

Figure 1. Overview of the Berai carbonate reservoir in the Kerendan Field Complex (modified after Bianchi et al., 2015). The structure map represents the top of the Berai carbonate. Location and trajectory of the wells selected for fracture hand-picking are shown in black. Results of fracture hand-picking at each well in the Berai carbonate are displayed at the bottom of the well traces. The red segments indicate position of major faults interpreted from 2D seismic data. The gas-water contact is shown with the black dashed line. The white trace indicates the position of the section presented in Figure 3.

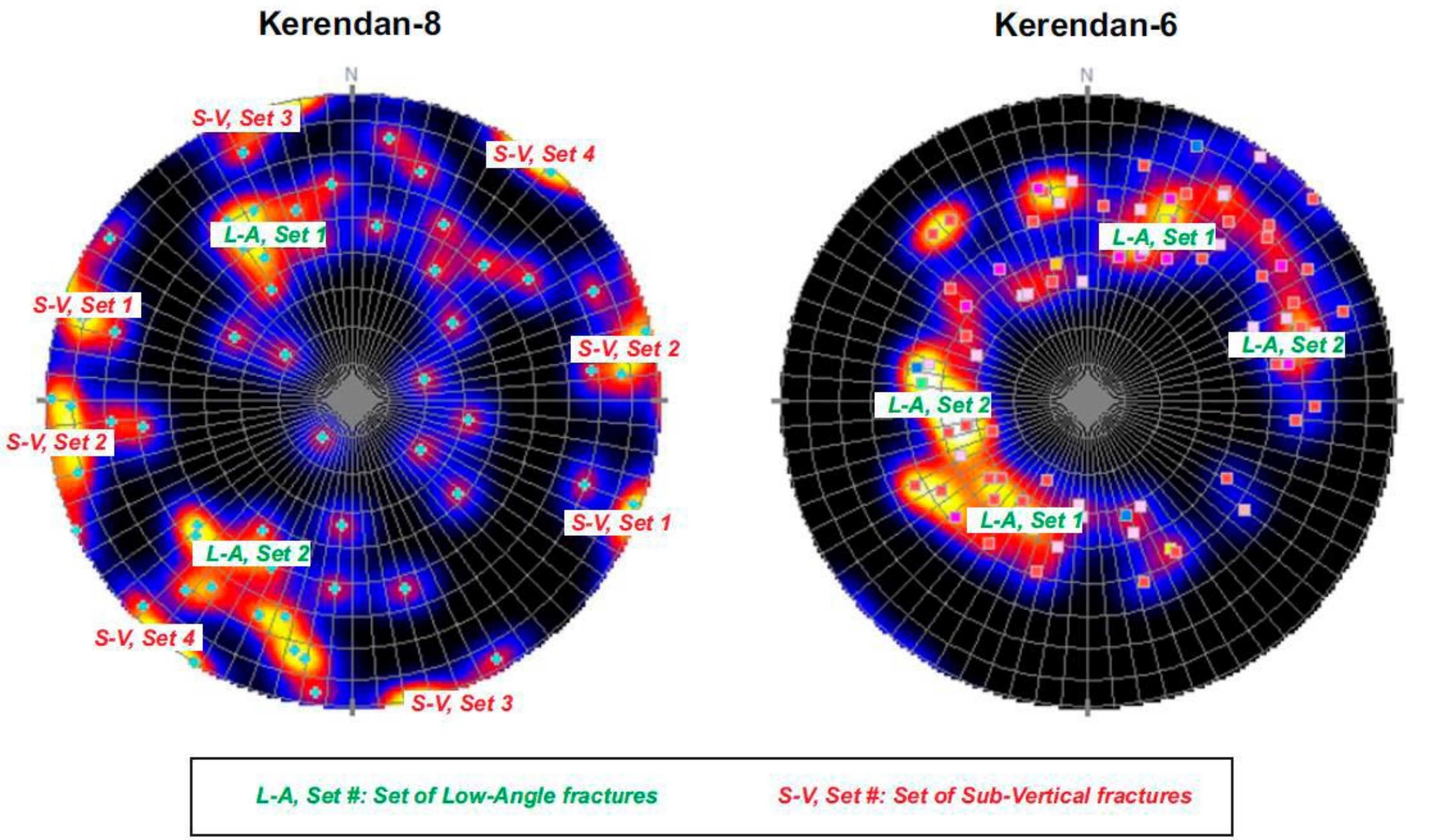

Figure 2. Polar projection of fracture planes identified from analysis of image logs in the Berai carbonate (Bianchi et al., 2015). The projection uses a lower Schmidt diagram with a density mapping of the poles distribution. Kerendan-8 (left) shows sub-vertical fracture sets (in red colour) and low-angle fracture sets (in green); no sub-vertical fracture sets are visible in Kerendan-6 (right).

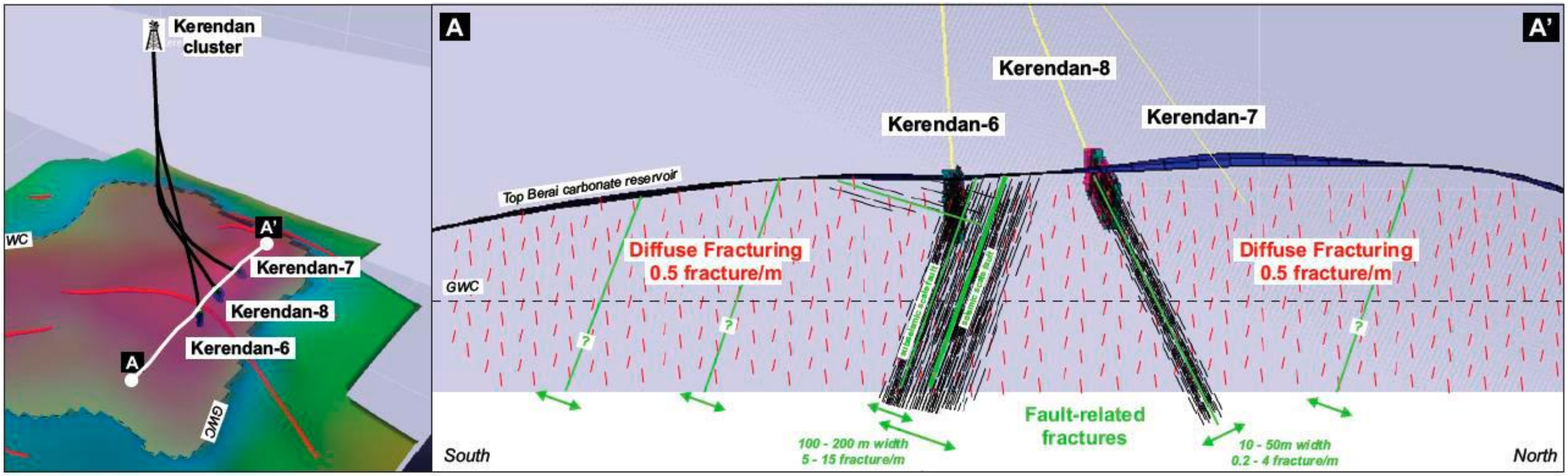

Figure 3. Conceptual modeling of fracture occurrence in the Berai carbonate near the Kerendan cluster, NE Kerendan Field Complex (modified after Bianchi et al., 2015). The model is extrapolated away from well trajectories assuming presence of faults below seismic resolution and associated fault-related fractures. Diffuse fracturing is displayed in red colour. Faults and fault-related fractures displayed in green and black colours.