Characterisation of Stress and Strength Dependent Fracture Flow Properties in Carbonate Reservoirs*

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Abstract

The vast majority of carbonate reservoirs are naturally fractured at various intensities and scales. These fractures are usually the main pathways for fluid flow of both hydrocarbons and water, and thus their properties control to a large degree both the production profile from producing wells and the well injectivity and sweep efficiency during secondary recovery. Because most fractures are stress-sensitive, their hydraulic conductivities will change with changes in bottom-hole-flowing and reservoir pressures causing variations in production profiles between wells. More specifically, fractures can hydraulically (partially) open or close due to a decrease (caused by injection) or increase (caused by production) in the effective stress. Because flow properties are a function of effective fracture aperture it is possible to predict reservoir behavior using the relationship between the mechanical behavior of natural fractures (in response to in situ stress and pore pressure changes) and their hydraulic properties. One obvious effect is by mode I or tensile opening of the natural fractures perpendicular to their plane which enhances their ability to transmit fluids. Another effect is that of mechanical shear failure whereby slip (i.e., shear failure) along the rough surface of an otherwise nearly closed fracture causes self-propping by natural asperities due to damage and the miss-match of the offset surfaces providing conduits for fluid flow (see the discussion of “critically-stressed fractures” in Barton et al., 1995). In carbonate reservoirs, where fracture opening can be enhanced by dissolution, it may also be that initially open fractures which fail in shear will tend to close, causing a decrease in their conductivity.

The ability of natural fractures to become critically-stressed and to remain hydraulically open due to shear slip is controlled by their intrinsic strength. The stronger the natural fracture, the more difficult it is to slip. Hence, strong natural fractures may remain hydraulically closed (or open where dissolution has created a connected pathway for fluid flow along the fracture) even for high ratios of shear to normal stress. Furthermore, fractures which are initially strong also tend to be initially stiffer than those that are initially weak, and stiffness can increase (by self-propping of initially nearly closed, weak fractures) or decrease (by collapse of initially strong, open fractures) after slip has occurred. Thus fracture stiffness and strength, both prior to and following shear slip, must be determined in order to model production or injection. Since carbonate reservoirs often contain multiple sets of natural fractures, and these may have different origins and thus different orientations and

properties, the mechanical behavior and characteristics of each fracture set must be considered separately in order to predict the overall flow characteristics of the reservoir over time (i.e., with changing pressure). For example, in one reservoir critically-stressed fractures may dominate flow behavior while in another, pre-existing, high-aperture and stiff joint sets predominate. The latter case is more likely to result in apparent stress insensitive behavior. The fracture orientation with respect to the present day stress field, the pore pressure, and the mechanical fracture properties together determine which processes are potentially active on an individual fracture plane or set.

To investigate the influence of these parameters and to better predict production behavior and understand the role natural fractures play in carbonate reservoir fluid flow, it is essential to build a robust geomechanical model of the stress magnitudes and orientations and to describe and characterize its natural fracture network and matrix mechanical properties as accurately as possible. The geomechanical model must also include knowledge of how in situ stresses change with depletion or/and injection. It is often imperative that analyses of these reservoir characteristics are carried out in 3D across the field and throughout the reservoir.

We model fracture equivalent aperture as a function both of the stresses and of the slip history or nearness to slip of the fracture. For this purpose, we use a simple equation (after Houssain, 2004; Tezuka et al., 2005; Moos and Barton, 2008; Barton, et al., 2009) to describe the variation in aperture as a function of effective normal stress. Different relationships govern pre- and post slip behavior. Utilizing this model, it is possible to compute the effective (relative) permeability of fractures of all orientations, given the current stress and pore pressure and the recent stress history. The parameters that govern fracture behavior by defining the unloaded aperture and the rate of change of aperture with increasing normal stress are likely to differ from one reservoir to the next. Thus it is necessary in each reservoir to constrain these parameters using fit-for-purpose well testing. During these tests the pressure is typically controlled such that it remains below the fracture gradient however even so in most cases these pressures are sufficient to cause some at least of the pre-existing fractures to become critically-stressed resulting in slip; since a change in injectivity is usually associated with this event a critical injection pressure can be derived which is related to the mechanical properties (i.e., stiffness and strength) of the natural fracture population.

To demonstrate the impact of varying the fracture flow and mechanical properties of each distinct fracture set on the total effective reservoir transmissivity, we applied this model to a carbonate reservoir for which both the present day in situ stress field and the natural fracture population were known. Three main fracture sets were identified in this reservoir: bedding, a weak fracture set (both with assumed zero cohesion and moderate sliding friction), and a strong fracture set (with assumed 500 psi cohesion and high sliding friction). The calculation assumes that all fractures contribute to flow to some extent, and that the relative productivity of a well of any orientation drilled into the reservoir can be computed by summing the contributions of all fractures as the product of the likelihood that they intersect the well and the likelihood that they are conductive. We assumed an injection pressure of 2,000 psi which is below the fracture gradient.

In Figure 1a, Figure 1b, and Figure 1c we plot scaled permeability (in these plots the permeability prior to slip of a fracture with zero applied normal stress is set to one) vs. normal stress for the three distinct fracture sets showing pre- and post-slip response in blue and green respectively. Permeability is plotted in relative units. We observe that for bedding (Figure 1a) and for the weak fracture set (Figure 1b), slip induces a six-fold permeability increase at zero effective normal stress as compared to pre-slip; this is because slipped fractures have larger apertures. These fractures close much more slowly with increasing stress after slip; hence, the increase in permeability is much larger for larger values of effective stress. In contrast, the strong fracture set (Figure 1c) shows the opposite behavior. Post slip, the permeability has been reduced to a tenth of its initial value, and the fracture is more stress-sensitive after slip than before. In contrast Figure 1d shows a model where all fractures sets are assumed to have the same flow properties. For the parameters used here the post-slip permeability is six times larger than pre-slip. This is similar to the changes induced by slip for the parameters used to compute Figure 1a and Figure 1b.

Figure 2 displays the cumulative pre- and post-slip productivity of wells of all orientations drilled into a reservoir for the model in which the three distinct fracture sets have different properties, compared with the well productivity if the flow properties of all three fracture sets are assumed to be the same. The trajectory of the "Best Well" (i.e., the well which will be most productive) is plotted on the stereonets in Figure 2 as a green dot at the position corresponding to its deviation and azimuth (vertical wells plot in the center of the figure, and horizontal wells plot around the edge). This is the position where the well optimally samples each of the primary groups of productive fractures. The unstimulated "best well trajectory" is very different if we assume that all fractures have the same flow and mechanical properties (Figure 1a) than it is for the model utilizing different fracture flow properties for each set (Figure 1c). Importantly the predicted productivity increase due to stimulation for the model using the same flow properties, in which stimulation increases fracture conductivity, is a factor of ~11 whereas the predicted increase for the model where fractures have different flow and mechanical properties is a factor of only ~2.5.

The results from this analysis provide a quantitative illustration of why in reservoirs with stiff, less stress sensitive fracture sets (e.g., carbonates), the impact of stress on production is far less pronounced as compared to those reservoirs with soft (i.e., highly stress-sensitive) fracture sets. Furthermore, in the former case the directions which have the greatest permeability (which are contained in the plane represented by the black great circles on each stereoplot in Figure 2) changes far less with stimulation compared to the change due to stimulation if the three fracture sets are equally soft.

Selected References

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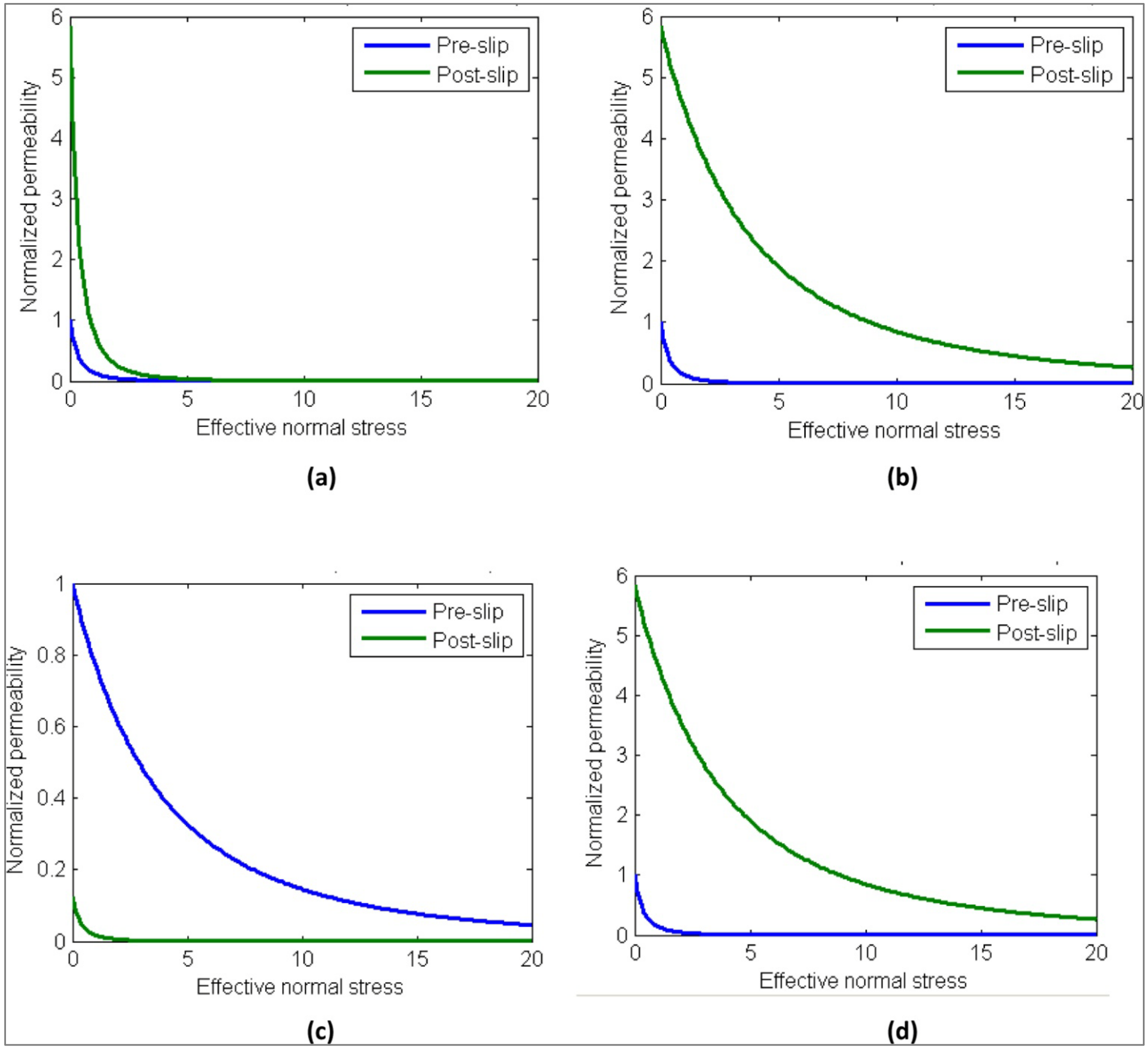

Figure 1. Permeability, relative to the permeability of a Mode I crack under zero effective normal stress, as a function of effective normal stress before and after shear slip for a carbonate reservoirs with three fracture populations: (a) bedding set, (b) weak fracture set, (c) strong fracture set, and (d) for all fracture sets when assuming the same flow and mechanical properties.

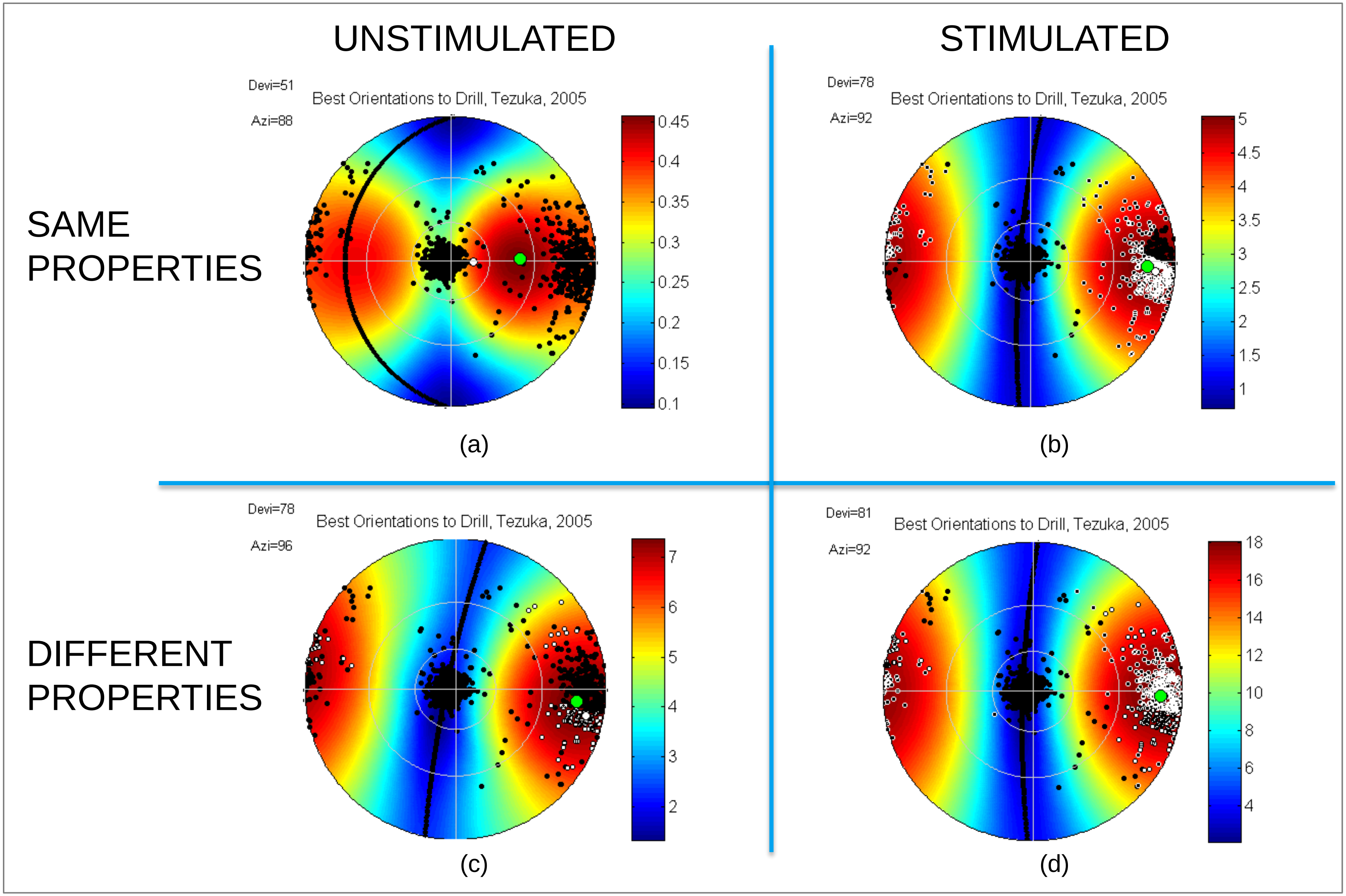

Figure 2. Cumulative relative well productivity superimposed on a stereonet to correlate with the three natural fracture populations from the sample carbonate reservoir: (a) pre-slip, (b) post-slip (after injection of 2,000 psi). The green dot displays the best well trajectory to intersect most of the productive natural fractures.