Quantitative correlation of fluid flow to curvature lineaments

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Summary

In most unconventional reservoirs, open fractures provide critical fluid conduits, and therefore, hydrocarbon production is heterogeneous and strongly dependent on the proximity of wells to the fractures. Attributes such as curvature do not "see" fractures; rather they are direct measures of real or apparent folds and flexures that are associated with. In this study, we extend a previously-developed, interpreter intensive workflow to generate a suite of azimuthally-limited attribute volumes that are sensitive to fracture orientation and intensity and can be directly correlated to production. Specifically, we cross correlate the strength and strike of curvature lineaments to production based on the hypothesis that production will be a function of the well's distance to "fractures" correlated with curvature.

We validate this workflow on a 3D seismic survey acquired over a Mississippian supermature carbonate reservoir in Dickman Field, Ness County, Kansas that was previously interpreted by explicit hand correlation. After calibration of the hypothesized fluid flow based on the strength and strike of the most-negative principal curvature, we find oil production increases with increasing distance from sealed NE-trending fractures while water production decreases with increasing distance from open NW-trending fractures.

Introduction

Fractures play a significant role in affecting reservoir performance. In conventional reservoirs with relatively good matrix porosity and permeability, open natural fractures can improve reservoir permeability allowing for higher production rate, while sealed fractures may provide a barrier to hydrocarbon flow in the rock matrix. In reservoirs with poor matrix characteristics, open fractures or fissures may serve as an important component of hydrocarbon storage, in addition to serving as the dominant fluid conduit. Furthermore, heterogeneous hydrocarbon production is often directly related to the spatial distribution of fracture sweet spots. In unconventional reservoirs, natural sealed fractures can be opened during hydraulic fracturing, thereby directing energy away from the unfractured rock and reducing stimulation performance (Rich, 2008).

Among all the attributes derived from poststack seismic amplitude data, volumetric curvature has proven to be one of the most promising attributes that allows for the mapping of fractures and faults. Although the relationship between fractures and curvature lineaments is quite complicated, many studies have demonstrated that open fractures are correlated with strong structural deformation. Hart (2002) and Nelson (2001) showed that open fractures are related to flexure in tight sandstone reservoirs. Narhari et al. (2009) found a direct correlation between curvature and coherence lineaments and natural fractures seen in image logs. Arasu et al. (2010) used Schmidt diagrams to derive an ant-tracking algorithm to estimate fracture sweet spots of a given azimuth. Hunt et al. (2010) directly correlated natural fractures seen on horizontal image logs and induced fractures measured by microseismic experiments with AVAz, VVAz and curvature. Guo et al. (2010) observed that high producing wells in a Woodford Shale survey correlated with the structural lows given by most-negative principal curvature k_2.

To our knowledge, one of the first attempts to correlate fluid flow with seismic volumetric curvature was made by Nissen et al. (2009). In their study of Dickman Field in Ness County, Kansas, Nissen et al. determined that fluid flow is not correlated to the curvature value seen at the well, but rather, is associated with the proximity of the well to the nearest fracture lineament. They observed a link between the fracture azimuth and water versus oil production, leading them to hypothesize that fractures at a particular azimuth may be open, while those at another may be sealed, and therefore should be treated differently. Unfortunately, this approach suffers from two pitfalls: 1) it requires extensive manual picking, and 2) it only accounts for the contribution of fluid flow from the nearest lineament. We generalize this idea by assuming: a) the fluid production is a sum of fluid flow from all fracture lineaments rather than the nearest, and b) that the fracture density is proportional to the curvature value. Specifically, we generate a suite of azimuthally-limited attribute volumes that can be directly correlated with production to understand the contribution of fluid flow from fracture lineaments at every azimuth, thereby testing whether a given fracture set is open or closed.

Theory

The diagram in Figure 1 shows the fluid flow at one well location. The fluid flow is approximately a function of κ/r, where κ is permeability, and r is distance from the well to the fracture lineament. If the joint or fracture plane is open, κ has a large value, whereas if it is sealed, κ approaches zero. Using calculus and assuming linear systems, a fluid charged fracture would provide a response proportional to the sum of a line of equally-spaced fluid injectors along the fracture. There are several steps necessary to generate an azimuthally-limited fracture intensity map, which is

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associated with joints and fractures. For Mississippian limestone in the following case study, diagenetic alteration is the major component, and the lineaments of interest are delineated by the most-negative principal curvature, k_2. The strike of these lineaments is the azimuth of maximum curvature, when $|k_2|>|k_1|$, and the azimuth of minimum curvature when $|k_2|\leq|k_1|$, where k_1 is the most-positive principal curvature, and the azimuths of these two curvatures are given by Rich (2008). Next, these lineaments are loaded into the workstation and the interpreter adjusts a gray-scale color bar to highlight features hypothesized to be associated with fractures.

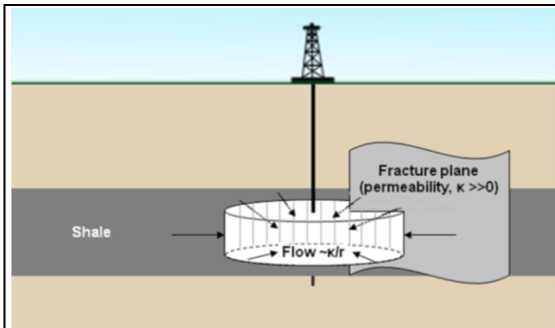

Figure 1: Diagram showing the fluid flow of a well controlled by the finite permeability of layer κ, with proximity to a highly permeable joint or fracture. We hypothesize that κ is large for open fractures, and approaches zero for sealed fractures.

The previous process results in a skeletonized image of fracture lineaments. Currently there are two principal methods of smoothing. The most common one is to convolve the skeletonized lineaments with a Gaussian operator, which can be efficiently achieved through iterative five- or nine-point smoothing. An alternative method is based on statistical correlations made by Nissen et al. (2009) and Green's function for fluid flow in or out of a vertical well (fault pillar) in a flat layers is $1/r$, where r is the radial distance $r=(x^2+y^2)^{1/2}$. From this we convolve our skeletonized fracture lineaments with the impulse response $1/r$.

Application in Dickman survey, KANSAS, USA

Dickman Field is an old Mississippian carbonate reservoir located to the west of the Central Kansas Uplift in Ness County, Kansas (Figure 2). The target Mississippian formation has a strong bottom water drive by the Western Interior Plains aquifer system and the Mississippian aquifer system is immediately underlain by the low porosity and permeability Gilmore City limestone, which provides a barrier to water flow. Previous studies have shown that reservoir rocks in Dickman Field generally contain solution-enhanced fractures. Some of these fractures were subsequently filled by Pennsylvanian Shale, and act as barriers to fluid flow. Other fractures may have been opened by geologic processes, and thereby serve as fluid conduits.

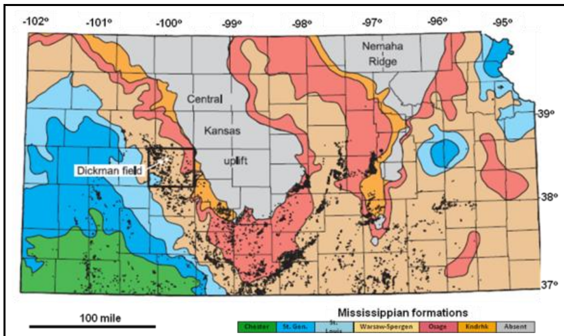

Figure 2: Map of the Mississippian subcrop in Kansas. Black box outlines Ness County, and white arrow points to the location of Dickman Field. Black dots represent oil production locations. Colors represent different geologic formations. (from Nissen et al., 2009)

The seismic survey utilized in this study covers a larger area than that of Nissen et al. (2009). Figure 3a shows the time-structure map of the top of Gilmore City horizon. Figures 3c and 3b show two vertical seismic lines AA' and BB', respectively, where yellow arrows indicate collapse features. In Dickman Field, Nissen et al. (2009) found that fractures gave rise to the most-negative curvature lineaments; the exact cause is uncertain. Figure 4a displays the horizon slice of the most negative principal curvature (k_2), along the Gilmore City limestone. while Figure 4b illustrates the skeletionized map. According to the two maps, the majority of lineaments align along NE-SW

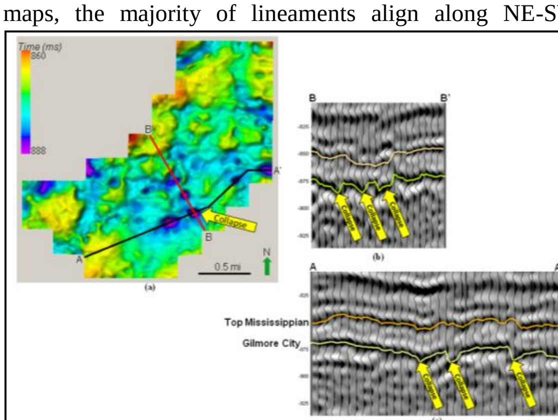

Figure 3: (a) Shaded relief time-structure map of the top of Gilmore City horizon underlying the Mississippian reservoir (b) BB', and (c) AA', show data quality (see (a) for cross section locations). Yellow arrows indicate possible collapsed features?

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direction, while some lineaments align along NW-SE direction.

Figure 5a shows the strike of the most-negative principal curvature k_2 modulated by its strength, which allows definition of fracture sets from different azimuths. Figure 5b is the 3D visualization of the same co-rendered volume using transparency display. Note that the solution-enhanced fractures in the Mississippian bedrock have good vertical continuity, and therefore mapping of fracture lineaments within the Gilmore City limestone is sufficient to illuminate fracture patterns throughout the entire Mississippian interval.

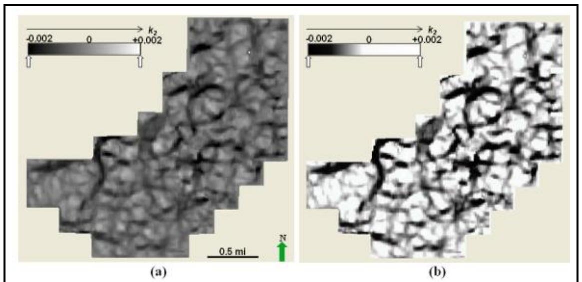

Figure 4: (a) Horizon slices through the Gilmore City showing most-negative structural curvature, k_2. (b) “Skeletonized” image obtained by interactively adjusting the color bar to delineate features interpreted to be associated with fractures.

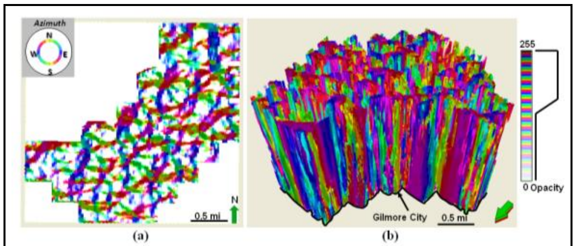

Figure 5: (a) Co-rendered volume from the most-negative structural curvature k_2 and strike of k_2, which allows definition of “fracture” sets of different azimuths. (b) 3D view of the co-rendered volume from k_2 and strike of k_2.

We generated twelve azimuthally-limited hypothesized fluid flow maps from the most-negative principal curvature k_2 and its strike with an azimuthal increment of 15^o with the goal of reproducing the correlation between 5-year oil production, water production, and fractures azimuth described by Nissen et al. (2009). Figure 6 shows these azimuthally-limited maps with oil production bubbles. Bubble size represents relative oil production. We see the map generated from fracture lineaments with azimuth 45^o has the largest negative cross-correlation, which implies the NE-trending fractures are not fluid conduits, as was implied in the generation of the fluid flow maps, but rather form a barrier to oil flow through the rock matrix. Figure 7 shows correlation between the same twelve maps with water production. This time, the hypothesized fluid flow generated from fracture-related lineaments with an orientation of 135^o have the strongest correlation, which means NW-SE-striking fractures might be open, and may channel water from the underlying aquifer. These two observations are consistent with the conclusions drawn by Nissen et al. (2009), which validate the feasibility of the proposed calibration approach.

Conclusions

We present a new workflow to quantitatively correlate the fracture-related curvature lineaments from different azimuths to the production data. This approach hypothesizes that open natural fractures or closed fractures that are easily opened by hydraulic fracturing act as the dominant fluid conduits in the reservoir. Assuming one fracture is composed of a set of point fluid injectors, we can predict the hypothesized fracture “fluid flow” from different azimuths through integration of the contribution from all point fluid injectors. We demonstrate that this workflow can be employed to investigate the fracture characteristics (open or sealed) by applying it to a carbonate Field in Kansas.

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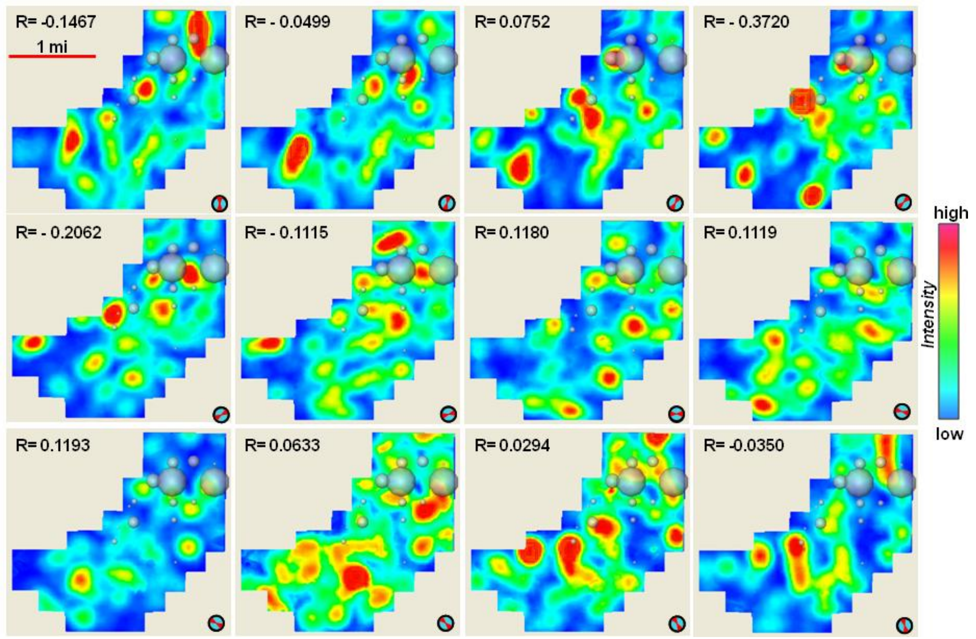

Figure 6: 5-year oil production against hypothesized fracture fluid flow computed from k_2 curvature and its strike. The strongest negative correlation at azimuth 45^o and 60^o suggests the NE-SW trending fractures might be sealed, acting as the barrier to fluid flow. Bubble size represents relative oil production.

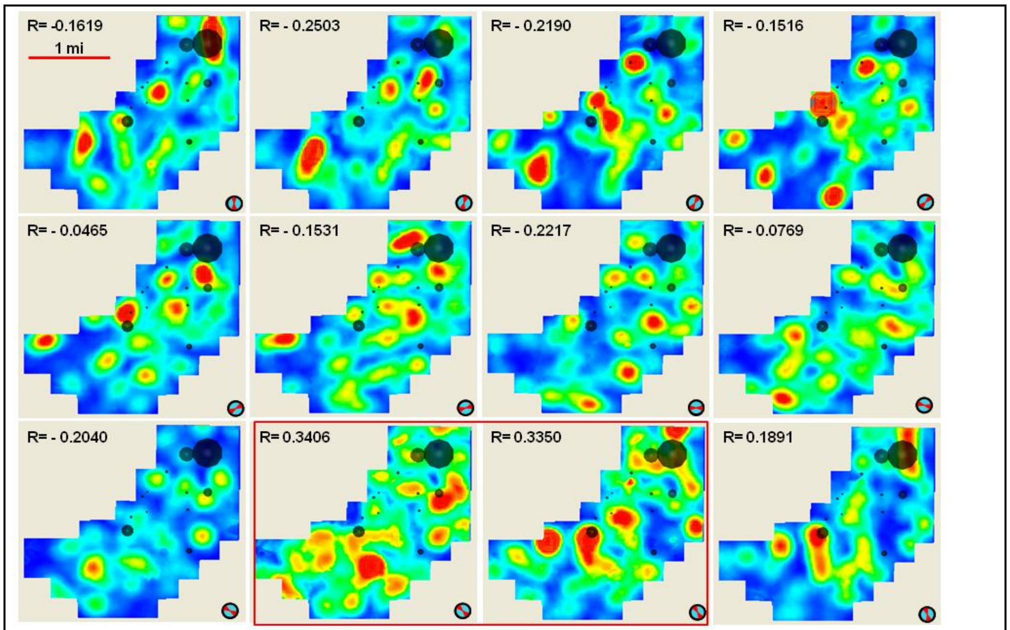

Figure 7: 5-year water production against hypothesized fracture fluid flow computed from k_2 curvature and k_2 strike. The strongest positive correlation at -45^o suggests that NW-SE-trending fractures are open, which supports previous work by Nissen et al. (2009). Bubble size represents relative water production.

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