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# Fracture Diagenesis and Producibility in Tight Gas Sandstones

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## Abstract

Fractures in tight gas sandstone remain challenging to characterize or predict accurately. Here we recapitulate recent work on continuity of fracture porosity and its important effect on fluid flow. Natural cement precipitation (diagenesis) in fractures can preserve fluid conduits by propping fractures open or otherwise reducing stress sensitivity of fracture permeability. It can also impede fluid flow by reducing effective fracture length, or occluding porosity. We report patterns of natural fracture growth and decay that are extensively influenced by diagenesis. These patterns typify many fractured siliciclastic and carbonate rocks. We show how appreciation of diagenetic effects can be used to improve accuracy of predictions of fracture attributes and illustrate implications for fluid-flow simulation. Our results also imply that fractures will not tend to close under subsurface loading conditions in many tectonic settings. Chemical alteration and the interactions of diagenetic reactions with rock properties and the *in situ* stress dictate the location of open fractured flow conduits.

## Introduction

A 1991 review of the geology and engineering of tight gas sandstones collated published evidence for natural fractures in all U.S. tight gas plays (Dutton *et al.*, 1993). The evidence included the presence of fractures in core and on image logs and production responses that frequently differed from those expected from the rock mass permeability and porosity alone. Subsequent research, including several cored horizontal wells collected by industry and in federal research projects, corroborates the widespread occurrence of fractures. But the understanding of their effect on producibility remains incomplete. Although many reservoirs having low porosity probably are productive because natural fractures enhance hydrocarbon delivery to well-bores, exploration and development decisions must often be made in the face of uncertainty about how fractures contribute to production and how these contributions (or lack of contribution) vary on field and play scale. The characterization of naturally fractured reservoirs continues to challenge geoscientists owing to the unavoidable difficulty in obtaining meaningful subsurface fracture samples (*e.g.*, Narr and Suppe, 1991).

Investigations of fractures include conventional fractured core description (Nelson, 1985; Hooker *et al.*, 2009) (Fig. 1), log analysis (Barton and Moos, 2009), geophysical methods (Sayers, 2007; Davis and Benson, 2009) and outcrop analogs (*e.g.*, Hennings *et al.*, 2000; Laubach and Ward, 2006) (Fig. 2). The focus of many such studies is on open natural fractures, since these may locally enhance permeability or even augment storage capacity. Yet tight gas sandstone core studies reveal both open and sealed fractures. Here we explore the consequences of one aspect of cement deposits that seal or partly seal fractures and how evidence from core studies and tight gas sandstone analog outcrop studies can be used to guide how diagenesis is accounted for in geomechanical models. These core and outcrop studies show that cement precipitation (diagenesis) and fracture are often linked processes (Fig. 3). For example in quartz-lined fractures common in sandstones that have been exposed to elevated temperatures (Laubach, 2003; Laubach *et al.*, 2004b) textures in the cements show that these deposits formed, in part, while fractures were actively opening. For fracture patterns generated by geomechanical models where aperture length and fracture network geometry reflect subcritical crack growth, realistic fracture geometries can be generated in response to small strain loading (Olson, 2007). Physical connectivity in the fracture networks depends on strain anisotropy but is typically high based on trace pattern geometry. When the effects of diagenesis are added, however, where smaller aperture fracture segments are preferentially filled, connectivity is significantly reduced. Understanding how fracture and diagenesis are linked can help clarify the controls on tight gas sandstone producibility.

## Cement precipitation and fracture

Cement precipitation and fracture can interact in several ways. For example, cement can have a strong influence on sandstone mechanical properties, helping to localize fractures in certain depth intervals (Fig. 1) or sandstone rock types (Fig. 3) (Laubach *et al.*, 2009). Cement in fractures can line or locally bridge between the walls of fractures (Fig. 3), and if present in large enough volumes, block fracture pore space and impede flow in fractures. To illustrate the role of cement deposition during fracture we focus on quartz cement in fractured sandstone. Quartz is the most abundant and widespread cement in sandstones that are exposed to temperatures in excess of ~90ºC for geologically significant periods. Therefore, it should not be surprising that many fractures in moderately to deeply buried sandstones show some porosity loss due to quartz cementation (Laubach *et al.*, 2004a). Using the concept that kinetics of quartz crystal precipitation is the rate limiting process for overall growth rate, quartz cementation rates are a function of temperature and nucleation surface area (Lander *et al.*, 2002; Lander *et al.*, 2008).

### *Opening rate and timing*

Fractures in tight gas sandstones locally exhibit crack-seal textures within isolated cement bridges (Figs. 3 5). These textures show that cement deposits and fracture growth are contemporaneous. Cement deposited during fracturing has been called synkinematic since it is contemporaneous with movement (separation) of the fracture walls (Laubach, 2003). In a wide range of sandstones there is a threshold value of the kinematic fracture opening (separation between two previously adjacent points across the fracture regardless of later mineral filling) above which fracture porosity is at least partially preserved and below which fractures are completely filled. This fracture aperture size is the emergent threshold (Laubach 2003). In some cases, synkinematic cement may locally bridge the fracture, while porosity is preserved elsewhere as illustrated in Figures 3 and 4.

Becker *et al.* (2009) describe fluid inclusions within isolated cement deposits in otherwise open fractures (Fig. 5A, B) that record the timing and rate at which fractures open. Fluid inclusions frequently contain both aqueous fluid and methane-rich gas inclusions (Fig. 5C) indicative of fluid trapping, quartz cement growth, and fracture opening during hydrocarbon charge of the reservoir. For example, quartz deposits in opening-mode fractures of the Cretaceous Travis Peak Formation (East Texas) provide a textural and fluid inclusion record of incremental fracture opening. Based on fluid inclusion microthermometry and Raman microprobe analyses, we determined that these inclusions contain methane-saturated calcic brine trapped over temperatures from ~134°C to ~150°C (Fig. 5D). Using textural cross-cutting relations to infer the sequence of cement growth, we have reconstructed the fluid temperature and pore fluid pressure evolution during fracture opening. In combination with burial evolution models, this reconstruction indicates that fracture opening started at near-maximum burial at ~48-42 Ma and above-hydrostatic pore fluid pressure conditions and continued during partial exhumation until present times under steadily declining pore fluid pressure.

Evidence of fracture timing is a key ingredient for predictive structural models. This East Texas study demonstrates the feasibility of determining timing for fractures in tight gas sandstones and illustrating that fractures in tight-gas reservoirs can remain open and available for fluid flow for geologically extended periods. Similar studies in the Piceance Basin, Colorado, in other producing areas, and in several outcrop analogs, show that the types of microstructural features we documented in East Texas are widespread in tight gas sandstones. Simulations of quartz cementation within fractures by Lander *et al.* (2002) show that porosity is a function of the ratio of the rate of net fracture opening to the rate of quartz precipitation. Interestingly similar structures are found in dolomite-lined fractures that typify many dolostones (Gale *et al.*, 2009), implying that similar structural diagenetic processes affect carbonate rocks.

### *Outcrop examples*

Quartz deposits similar to those found in core have also been found in fracture systems in outcrop (Laubach and Ward, 2006; Laubach and Diaz-Tushman, 2009). These studies show that quartz systematically fills in fractures, first sealing small fractures and the narrower parts of large fractures such as tips and the tapering parts of interconnected fractures where segments meet. In the example of the Cambrian Eriboll sandstone fractures (Laubach and Diaz-Tushman, 2009), quartz precipitation accompanies fracture growth, initially without sealing large fractures. But with time, cementation destroys fracture porosity, which is ephemeral owing to quartz precipitation. Where the precipitation step governs quartz accumulation, the potential for fractures to persist as fluid conduits depends strongly on temperature and fracture size. Calculations for fracture sealing, based for example on the rates calibrated by fluid inclusions and burial history described by Becker *et al.* (2009), imply that the duration of diagenetic sealing for large fractures can be on the order of millions and perhaps tens of millions of years in deep-basin settings. In contrast, because millimeter-scale and smaller fractures have small volume relative to surface area, they will tend to seal readily. Rapid rates of microfracture sealing suggest that even the youngest and coolest Eriboll sandstone microfractures may have sealed in as little as a few thousand years; the rates are extrapolated from laboratory observations (Brantley, 1990), inferred using rates from Lander *et al.* (2008) or implied by fracture porosity in natural examples in basins having well constrained thermal and fracture sealing histories.

All Eriboll sandstone sets have many more small fractures than large. For a given set, fracture porosity and surface area are concentrated in fractures having apertures less than 0.1 mm owing to size distributions that approximate power laws (Marrett, 1996). These are the same types of size distributions that have been documented in subsurface tight gas sandstones in horizontal core (Hooker *et al.*, 2009, Piceance Basin). Although all microfractures in a set are unlikely to have formed at one time, these size distributions and cross-cutting relations with other sets imply high disseminated fracture porosity that is transient. For a specific deformation event, diagenesis rapidly converts penetrative arrays of mostly small fractures into sparse arrays of large and open fractures. Large quartz-bridged fractures may linger as potential fluid conduits, possibly even where they are misoriented with respect to evolving loading conditions that might otherwise induce mechanical closure. According to models of fluid flow in disconnected fracture systems (Philip et al., 2005), flow would tend to be in uniform fronts through penetrative arrays but might be channelized when only a few large fractures remain. Eventually, even large fractures are closed.

Outcrop studies in conventional clastic reservoirs and reservoir outcrop analogs have demonstrated the influence of larger scale structures such as faults and folds on the occurrence of opening-mode fractures (*e.g.*, Hennings *et al.*, 2000; Myers and Aydin, 2004; Bellahsen *et al.*, 2006; Eichhubl *et al.*, 2009). Although the structural relations between fracturing and larger scale deformation should apply equally to tight-gas sandstone reservoirs, the structural-diagenetic interactions are likely to be more pronounced at the higher temperatures in tight-gas reservoirs. The implications of the structural models derived from conventional reservoirs and reservoir analogs have not been tested in tight-gas settings.

### *Stress sensitivity*

Cement that lines or bridges fractures also will decrease fracture compliance, even for fractures that have comparatively high porosities. Conventional wisdom assumes that fluids prefer to flow along fractures oriented parallel or nearly parallel to modern-day maximum horizontal compressive stress, or $S_{H\max}$. The reasoning is that these fractures have the lowest normal stresses across them and therefore provide the least resistance to flow. For example, this view governs how geophysicists design and interpret seismic experiments to probe fracture fluid pathways in the deep subsurface.

In some cases, quantifying the stress state (magnitudes and directions) is a useful proxy for fractures observations, with the assumption that opening mode fractures parallel to $S_{H\max}$ are most likely to be conductive (Heffer and Lean, 1993), or faults that are critically stressed are the key to reservoir deliverability (Barton *et al.*, 1995). But this is apparently not generally the case for tight gas sandstones, where open and conductive fractures are found at a wide range of angles to $S_{H\max}$ (Laubach *et al.*, 2004a). In tight gas sandstone core, stress measurement and fluid-flow data indicates that $S_{H\max}$ does not *necessarily* coincide with the direction of open natural fractures in the subsurface (>3 km depth). Consequently, in situ stress direction cannot be considered to predict or control the direction of maximum permeability in these rocks.

## Large sealed fractures

Where effective stress is compressive and fractures are expected to be closed, chemical alteration dictates the location of open conduits, either preserving or destroying fracture flow pathways no matter their orientation. Quartz cement accumulates in systematic patterns within fractures, typically sealing microfractures but merely lining or bridging large fractures (Fig. 5A). Open fractures are preserved primarily because quartz cement precipitated in the rock mass effectively locks fractures open (Olson *et al.*, 2007), and because the most common cement in tight gas sandstones, quartz, is ineffective in sealing large fractures. With knowledge of burial history and fracture timing, the minimum size of open fractures (the *emergent threshold*) can frequently be predicted accurately.

Diagenetic processes are also responsible for sealing some large fractures (Laubach, 2003). In tight gas sandstones, the phases responsible for sealing large fractures are commonly carbonate minerals. The distribution of these damaging late cements may be highly heterogeneous within a field or even individual sandstone. Rock composition, stratigraphic and structural position, and basin plumbing can all affect the distribution of late cements and the pattern of sealed fractures. Understanding these controls is an important goal of ongoing research.

## Geomechanical fracture pattern modeling

The empirical observation of emergent threshold suggests that larger aperture fractures are more likely to have preserved porosity than smaller aperture fractures. Fractures with apertures above emergent threshold may be those that opened fastest, where opening rate exceeded cement precipitation rate. Alternatively, smaller aperture fractures could just be the small size fracture of the mechanically determined aperture population because of length, orientation or the mechanical interaction with neighboring fractures, these fractures never reach large aperture and are thus destined to be plugged. Modeling and comparisons to field data demonstrate that subcritical crack growth can be used to explain size distributions of fracture length which can ultimately be related to fracture aperture (Olson, 2003).

## Fracture permeability estimation

Philip *et al.* (2005) and Olson *et al.* (2009) estimated equivalent permeabilities for a variety of fracture patterns generated by the geomechanical model of Olson (2004) for various values of strain anisotropy, subcritical index, and layer thickness in an attempt to discern attributes that controlled flow in networks. Under higher strain anisotropy, single set networks were generated consisting of nonpercolating, parallel fractures, These results (Philip *et al.*, 2005) showed that permeability was dependent on fracture intensity as measured by cumulative length, but it was also influenced by average segment length. Patterns of the same cumulative trace length but larger average segment length had higher equivalent permeability than those with smaller average segment lengths. Imposing the effects of synkinematic cement on the fracture pattern preferentially occluded small aperture segments of the fractures, reducing average fracture length and diminishing effective permeability (Fig. 6).

Under lower strain anisotropy, cross-fracture sets often developed, improving the modeled network s based connectivity (Olson *et al.*, 2007; 2009). Imposing synkinematic cement of varying emergent threshold also preferentially filled the narrower fracture segments of the patterns and lowered permeability; however, for the cross-fractured networks, the most significant impact was the loss of connectivity and percolation (Fig. 7).

## Discussion and conclusion

Natural fractures may help or hinder stimulation operations, aiding the flow of gas *or* water, and augmenting or interfering with hydraulic fracture stimulation yet fracture characterization for the purpose of fluid flow estimation is challenging. Core observations show that cement deposits are an essential part of tight gas sandstone fracture systems. Geomechanical models provides one avenue by which fracture length, spacing, aperture and distributions can be calculated, but these results are not representative of the porosity structure of fracture systems in tight gas sandstones unless they also account for cement deposits. Even if fracture network geometry were precisely decipherable, modification of mechanically derived fractures by diagenesis is ubiquitous. There are systematics to diagenetic effects and these effects can be accounted for in modeling flow in fracture patterns. Results that closely resemble the permeability enhancement found in nature (found via well tests) can be generated by geomechanical models with added diagenesis. These provide more realistic templates for fluid flow simulation.

Because fracture models can be linked to readily observed diagenetic features as well as to more-difficult-to-sample fractures, the feasibility of systematically comparing and verifying model predictions with site-specific data is greatly increased. Our results also imply that fractures in tight gas sandstones will not tend to close under subsurface loading conditions in many tectonic settings, contrary to widely held views. These results need to be taken into account in interpretation on seismic data collected to detect and characterize fractures.

## Acknowledgments

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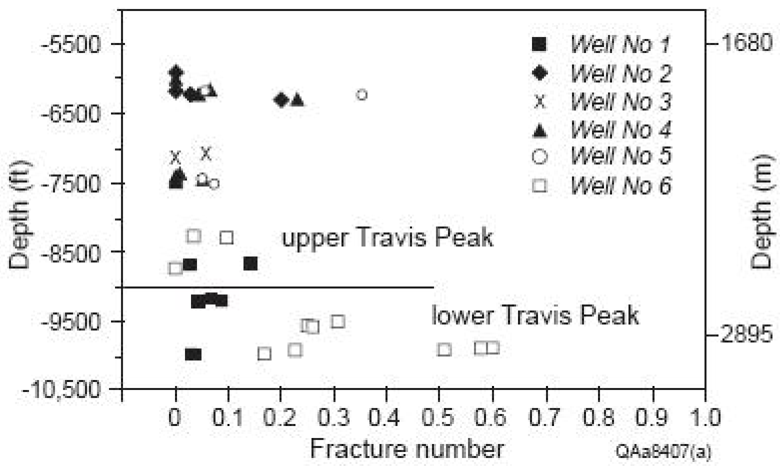


**Figure 1. Fracture abundance versus depth in Cretaceous Travis Peak Formation, East Texas, as shown by fracture number, a measure of fracture intensity. Here cumulative fracture height (all fractures) is shown from several depths, normalized to core length. Although fracture number has obvious limitations for depicting fracture size or arrangement, it is an objective measure and useful if overall fracture intensity is high and sampling extensive. For well locations see Laubach (1989).**

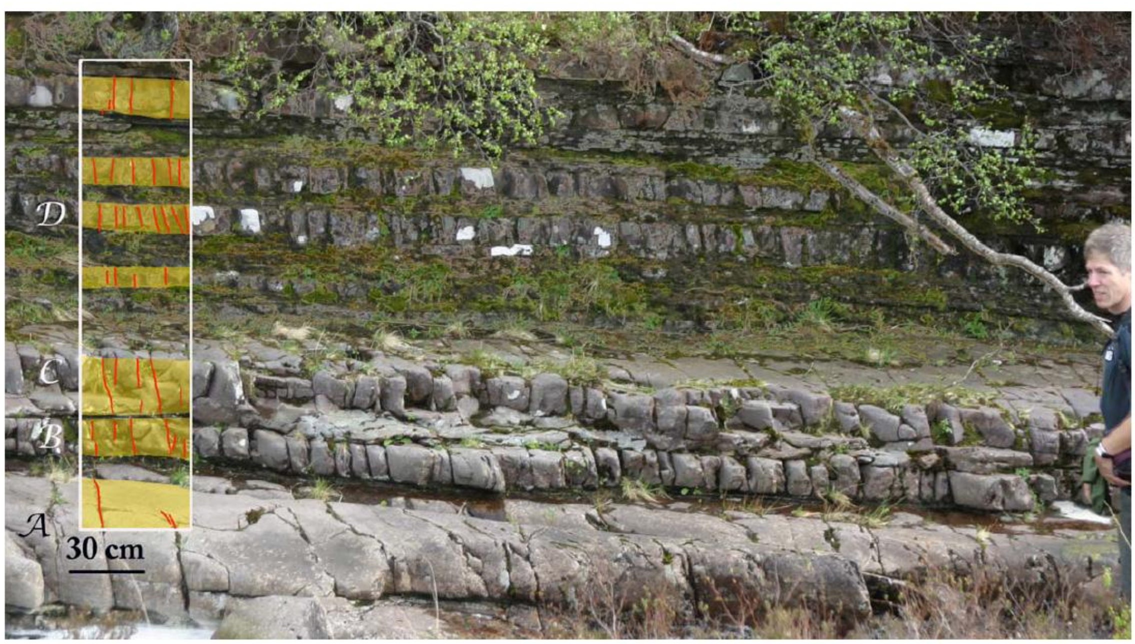


**Figure 2. A simple array of subvertical quartz lined, open fractures in Late Precambrian Torridonian Sandstone, NW Scotland. Study of outcrop fractures that have attributes that resemble those in tight gas sandstones, such as these (Ellis, 2009), can aid characterization and accurate prediction of the role of natural fractures in tight gas sandstones.**

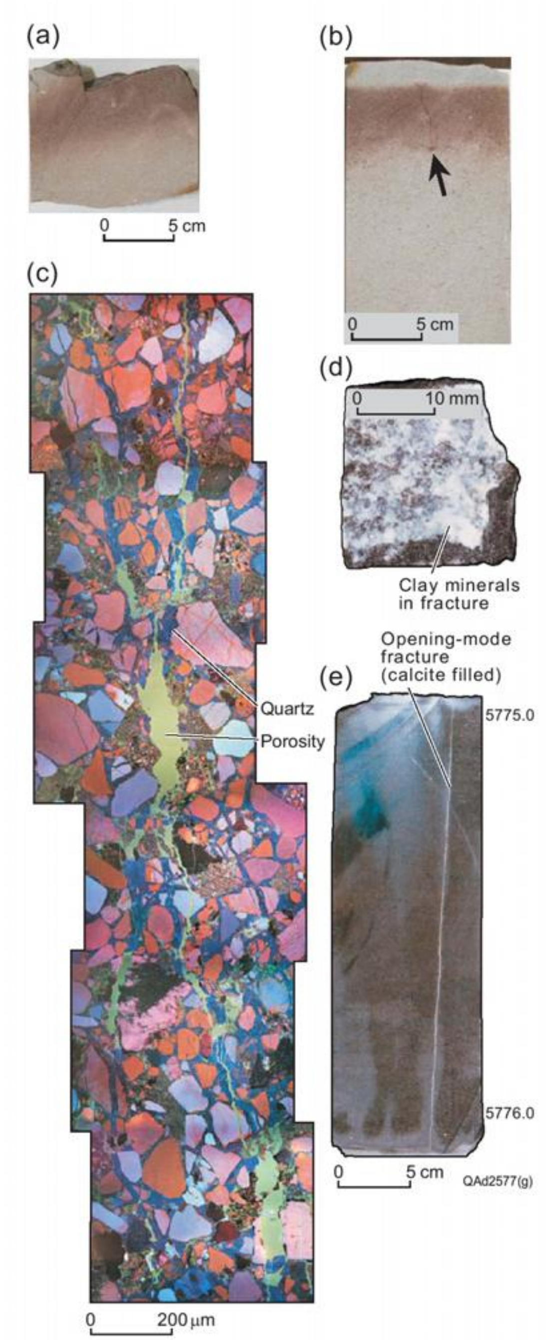


**Figure 3. Fractures, attributes, and rock types, Sonora Canyon sandstones. (A) Siderite-cemented layer (orange tinge). (B) Siderite-rich layer with fracture that stops at layer boundary (arrow). Fractures are localized within siderite-cemented layers and stop at layer boundaries, similar to veins in concretions, but thickness, persistence, volume, and widespread occurrence of siderite zones show that these rocks are essential reservoir components. (C) Color scanning electron microscope cathodoluminescence image of porous, quartz-lined fracture, from nonsideritic, quartz-cemented sandstone. (D) Clay minerals (white, along fracture face) lining sealed fracture within sideritic sandstone. (E) Calcite-filled fracture in nonsideritic sandstone. Early siderite-cemented localized an early fracture set (B, D); later quartz cement preferentially deposited outside siderite-cemented zones resulted in indistinguishable mechanical properties between siderite- and non-siderite zones; subsequent fractures (such as those in C and E) reflect these later-developed mechanical properties.**

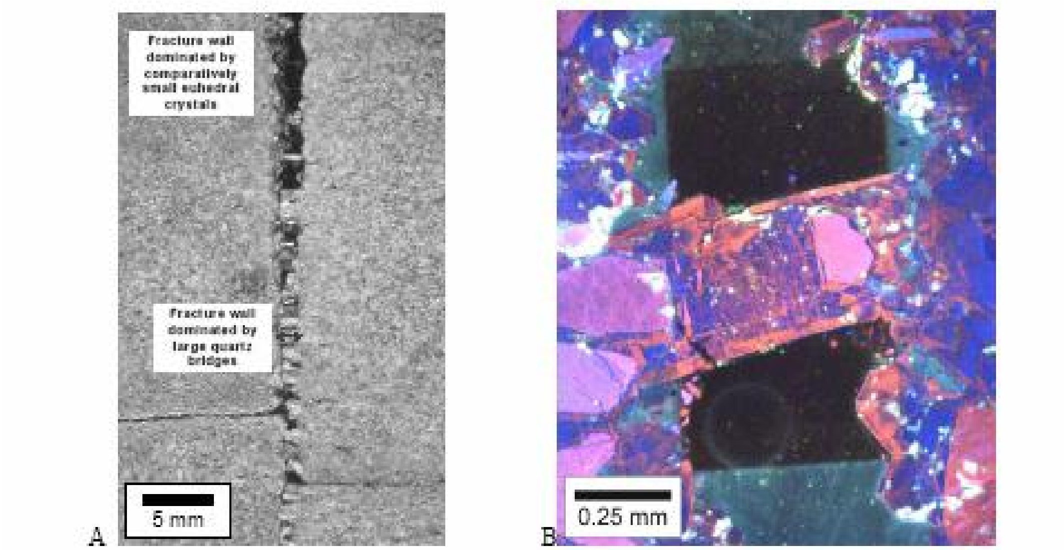


**Figure 4. Fractures and synkinematic cement. (A) Cretaceous Travis Peak Formation core sample near tip of a vertical fracture (core photograph). Quartz cement is more abundant toward tip of fracture (bottom part of image) than where aperture widens (top part of image). Sample depth is ~2986 m. See Laubach *et al.* (2004b) for more information. (B) Quartz cement bridge showing crack-seal texture. SEM-cathodoluminescence image, Travis Peak Formation.**

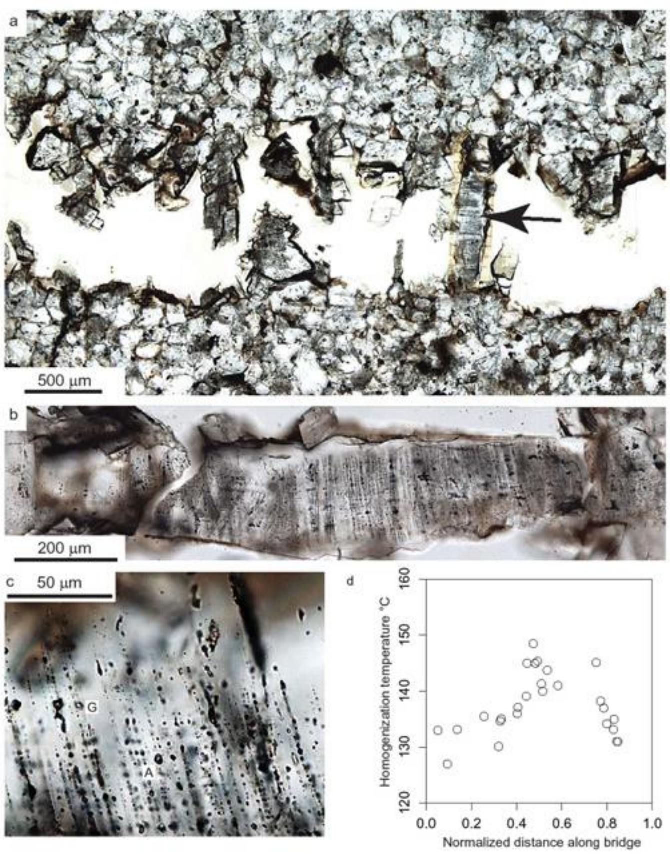


**Figure 5. (A) Quartz cement locally bridging across (arrow) an otherwise open fracture, Travis Peak Formation, 9840 ft, East Texas basin. Fracture walls are overgrown by quartz and dolomite cement. Uncemented fracture space is filled with epoxy (white). (B) Cement bridge (Travis Peak Fm.) containing closely-spaced parallel bands of fluid inclusions trapped during fracture opening and concurrent precipitation of the quartz cement bridge. Microthermometric analyses of fluid inclusions indicate fracture opening at temperatures of 130-150°C corresponding to deep burial and subsequent partial exhumation of the formation. (C) Detail of (B) containing two-phase aqueous (a) and single-phase gas-filled (g) inclusions. (D) Fluid inclusion homogenization temperatures for bridge in (B) plotted against normalized distance from left to right along bridge in (B). After Becker *et al.*, submitted.**

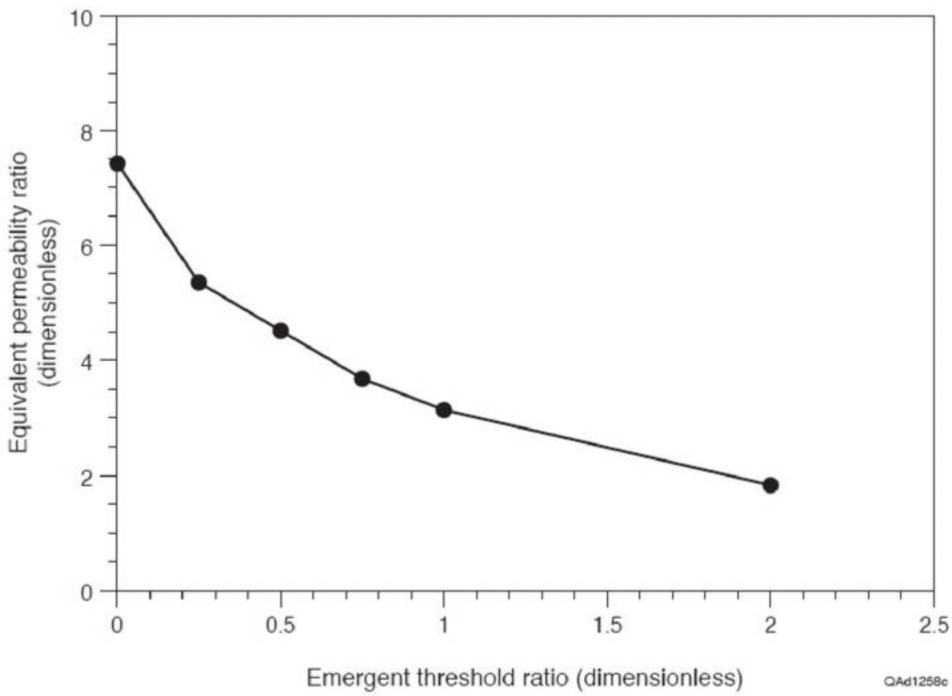


**Figure 6. Effect of synkinematic cement on equivalent permeability for a simulated fracture. After Philip *et al.* (2005) and Olson *et al.* (2009). The addition of a small amount of cement can drastically reduce permeability by reducing fracture network connectivity and average fracture length.**

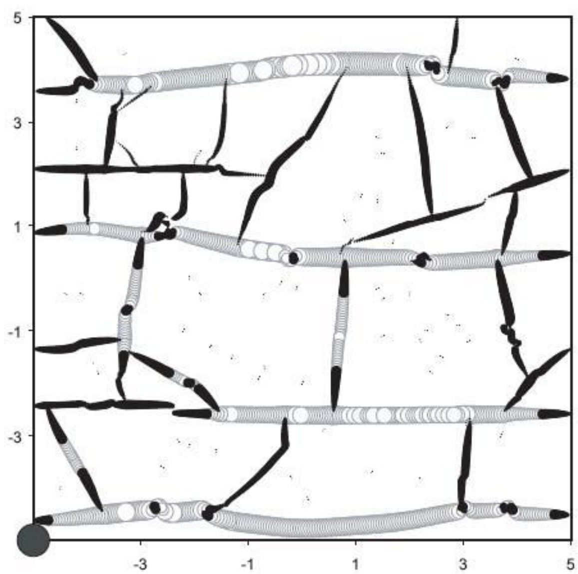


**Figure 7. Plot showing geomechanically generated fracture trace length and aperture patterns for a specified strain, mechanical layer thickness, and subcritical crack index. All segments having an aperture less than 0.6 mm (the given emergent threshold; *emergent threshold* defined in Laubach, 2003) in black to indicate they are closed. Note change in expected connectivity. See Olson (2004) and Olson *et al.* (2007).**