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Stratigraphic Controls on Fracture Distribution in the Austin Chalk: An Example from the First Shot Field, Gonzales Co., Texas

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A multidisciplinary study undertaken at the First Shot Field, Gonzales County, Texas (Figure 1) demonstrates that fracture distribution within the Austin Chalk Formation, and thus production, is stratigraphically controlled. Combining regional structural, stratigraphic, and geochemical work with subsurface mapping and detailed core fracture studies enabled us to develop a model for fracture formation that explains the observed stratigraphic distribution of fractures, the geographic distribution of Austin oils, and production. This model relates fracture formation to fluid expulsion from the Eagleford Shale and major shale breaks internal to the chalk. In addition, the model describes the partitioning of fracture intensity, oil types, and production into two distinct spatial domains within the field area.

The Austin Chalk is underlain by the Eagleford Shale and overlain by the Anacacho Limestone. An informal subsurface stratigraphy in the First Shot Field subdivides the formation into four clean chalk benches separated by intervening shales (Figure 2). The shales are referred to as “Ash Layers” by operators in the area because of their high gamma ray signature. Biomarker studies and consideration of source volumetrics show that the Eagleford Shale is the primary source rock for Austin oils. Along strike to the northeast and southwest the oils are a mixture of Eagleford and Austin sources, although the volumetric contribution from the Austin is likely small compared to the Eagleford. Within the field, local faults (discussed below) partition the oil system into two distinct families (Figure 3).

Regionally, the First Shot Field is astride the eastern flank of the San Marcos Arch and up-dip of the Gulf Coast Hingeline, which is locally defined by a series of large-displacement, down-to-the-coast faults known as the Karnes Trough. Locally, a prominent horst block, identified on seismic and from subsurface mapping, was active at the time of chalk deposition. Stratigraphic changes related to this depositional high include a thinned chalk section across the top of the horst, development of shallow-water shoal facies on the horst, and erosional removal or non-deposition of a prominent marl layer known as the “Fat Ash” from the top of the horst.

In this study, the distribution, orientation, and characteristics of natural and induced fractures from cores collected in two wells, the Robinson-Troell No.1 and Bell-Sample No.1, were measured and described. Each core was oriented using the viscous remanent component of the magnetic field to determine the present-day direction of North. The paleomagnetic pole orientation and the magnetic intensity as a function of vertical stratigraphic position were measured as well. In the Robinson-Troell No.1, a Formation Micro-Scanner (FMS) imaging log was acquired, providing the opportunity to compare core-measured fracture orientation and vertical distribution with interpreted fractures from the FMS imaging log.

Natural fracture intensity in both cores is greatest in the basal "D" chalk section directly overlying the Eagleford Shale. In addition, the chalk sections immediately adjacent to the principal shale breaks possess high fracture intensities (Figure 4). Oil-saturated fractures are also concentrated in the "D" chalk. Fractures in the "D" chalk and underlying Eagleford Shale are characterized by significant dissolution and minor secondary mineralization. Fractures at higher stratigraphic levels in the chalk show more brittle deformation characteristics without the associated diagenetic overprint. Natural fractures have a mean strike of N 40° E in the Robinson-Troell No.1 core and N 59° E in the Bell-Sample No.1 core. Oil-bearing fractures strike N 43° E and N 61° E in the Robinson-Troell No.1 and Bell-Sample No.1, respectively. In contrast to the natural fractures, drilling-induced fractures are abundant in the Robinson-Troell No.1 core in the "B" chalk interval, with an average strike of N 31° E. Drilling-induced fractures have a tightly clustered bimodal concentration characteristic of small-dihedral-angle shear fractures. Fractures interpreted from the FMS log in the Robinson-Troell No.1 well are most abundant in the "A" and "B" chalk intervals with an average strike of N 54° E, and overall FMS fracture intensity is an order of magnitude less than that measured in core.

In addition to fracture studies, paleomagnetic data provide critical constraints on the mechanism and timing of reservoir development. The Austin Chalk was deposited during the Cretaceous long normal polarity period. However, samples from the cores have a reversed-polarity paleomagnetic signature acquired during the early Tertiary as a diagenetic chemical remanent magnetization. Thermal demagnetization temperatures of 270°C and petrography indicate pyrrhotite is the primary carrier of the paleomagnetic signature. Magnetization intensities for samples from the "D" chalk interval are an order of magnitude greater than for samples at higher stratigraphic levels. This is consistent with diagenetic alteration driven by fluids derived from the underlying Eagleford Shale.

The foregoing observations support a model of fracture development driven by fluid expulsion from the clay-rich "Ash" layers and Eagleford Shale. As a consequence of the very-low matrix permeability of clean chalk sections, even at modest burial depths, we infer that the expelled fluids locally elevated the pore pressure, making the effective confining pressure lower and allowing fluid-invaded chalk sections adjacent to the shales to fracture at lower differential stress. Timing of major fluid migration corresponds to maximum depth of burial and may also indicate fracturing is coincident with oil generation and expulsion. Higher fracture intensities down-dip of the First Shot Field horst, the partitioning of higher maturity oils down-dip of the horst block, and significantly higher initial and cumulative production for down-dip wells all suggest that fracturing fluids were expelled from the more deeply buried section in the region of the Karnes trough. These fluids apparently migrated up-dip along bedding until encountering the horst block which acted as a barrier to further up-dip migration. As a consequence, the fluids then invaded the surrounding chalk as pore pressure increased until being reduced by fracturing. Fracturing up-dip of the horst block is likely driven by a similar mechanism of fluid expulsion, but the origin of the fluids is problematical, as the oils up-dip of the horst block derive from a significantly less mature source area.

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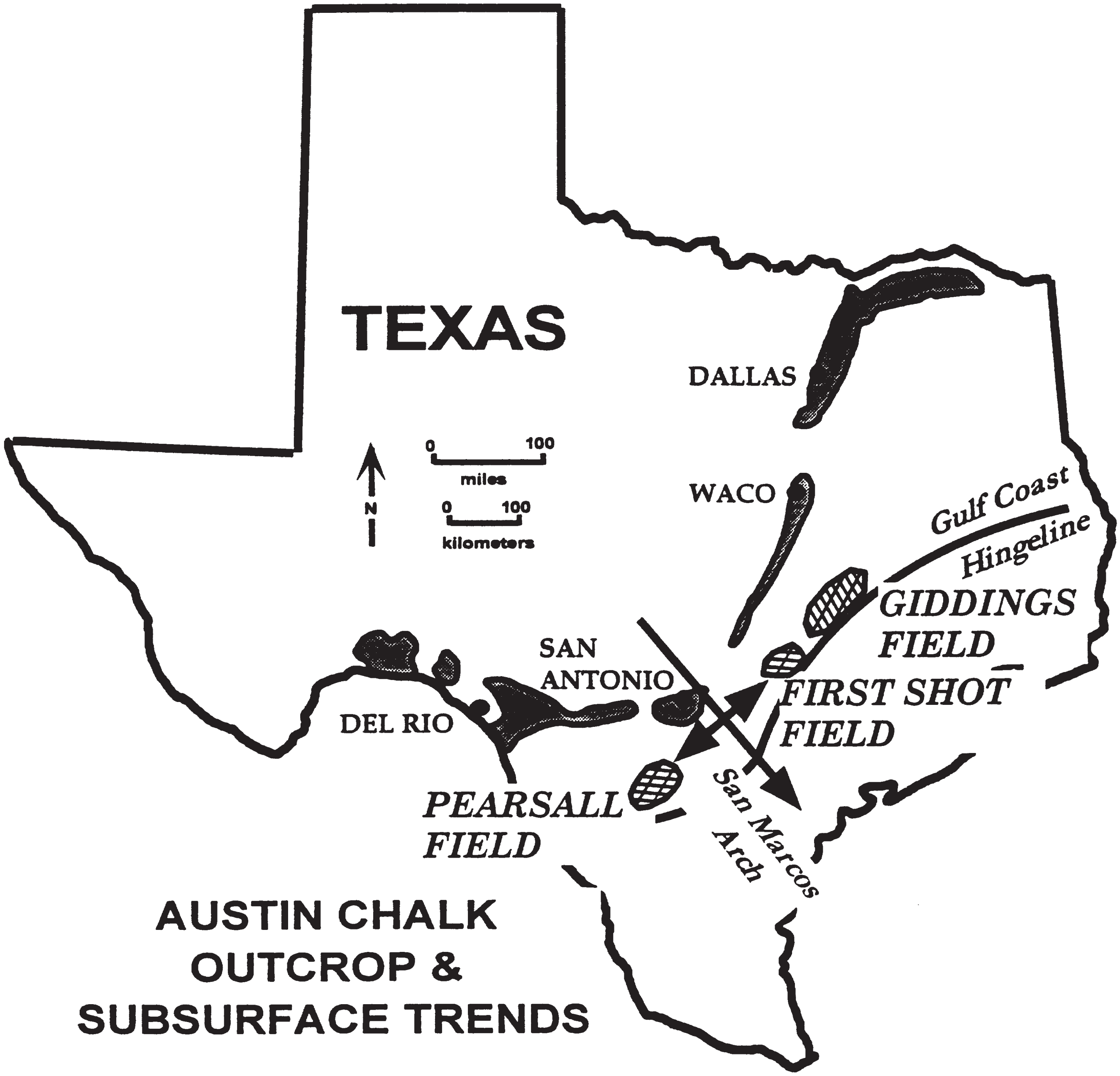

Figure 1. Geographic reference map to Austin Chalk outcrop trend (shaded), producing fields discussed in text (cross-hatched), and regional structural features including the San Marcos Arch and Cretaceous Gulf Coast hinge line.

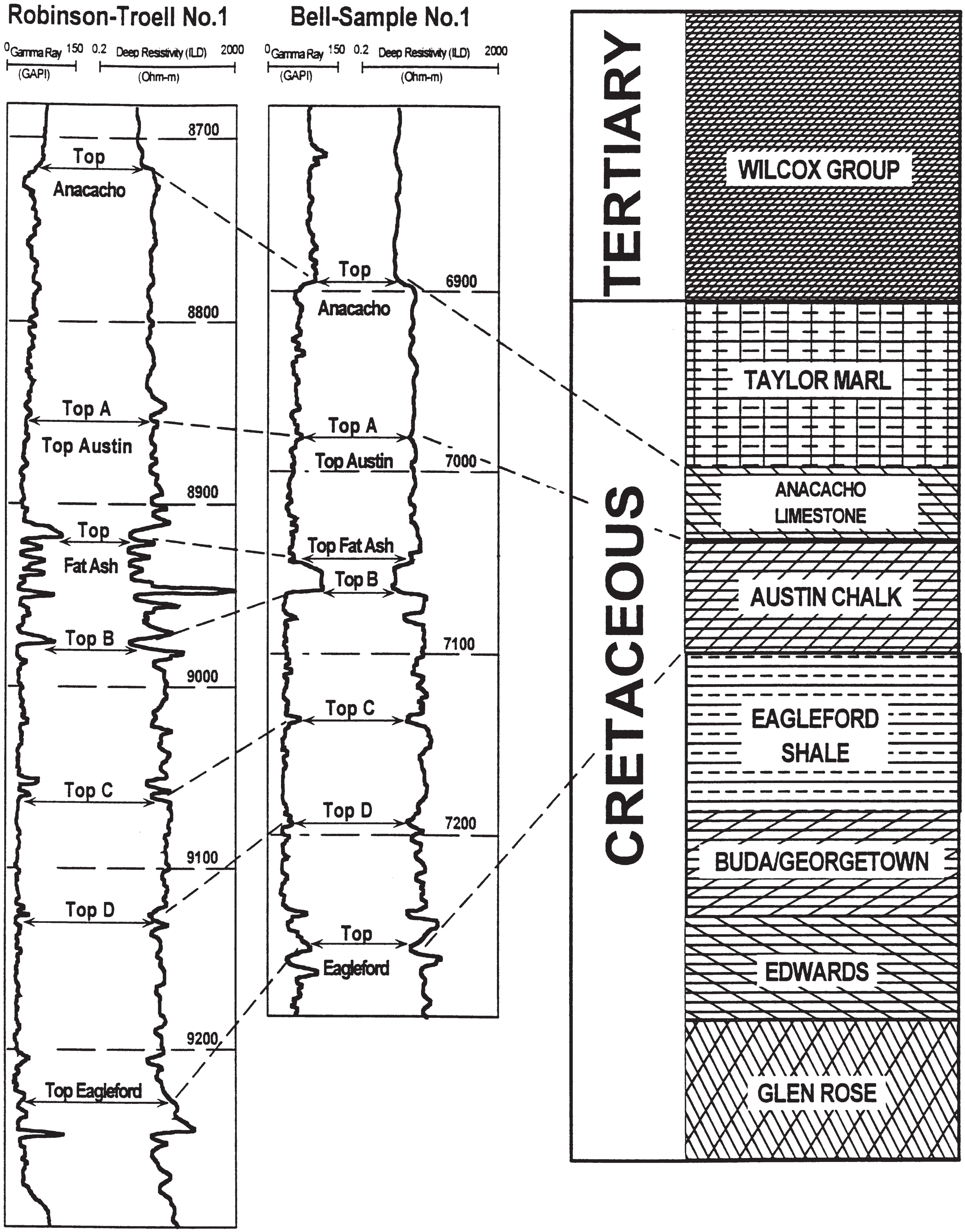

Figure 2. Correlated well logs and simplified section for the Austin Chalk and surrounding strata; all depths in feet.

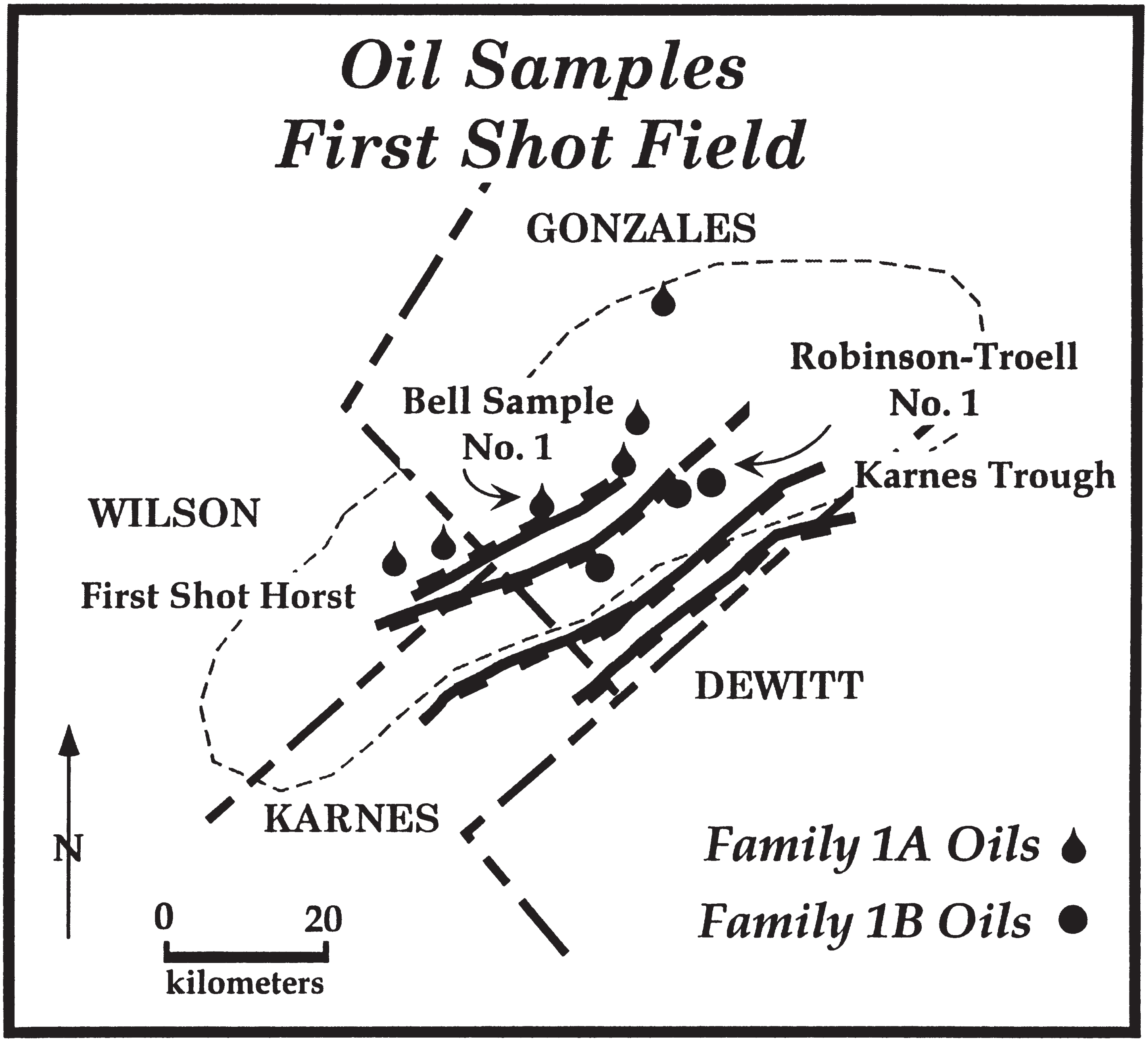

Figure 3. Map showing the location of oil samples in the First Shot Field (dashed outline), county lines, and major faults in and adjacent to the field.

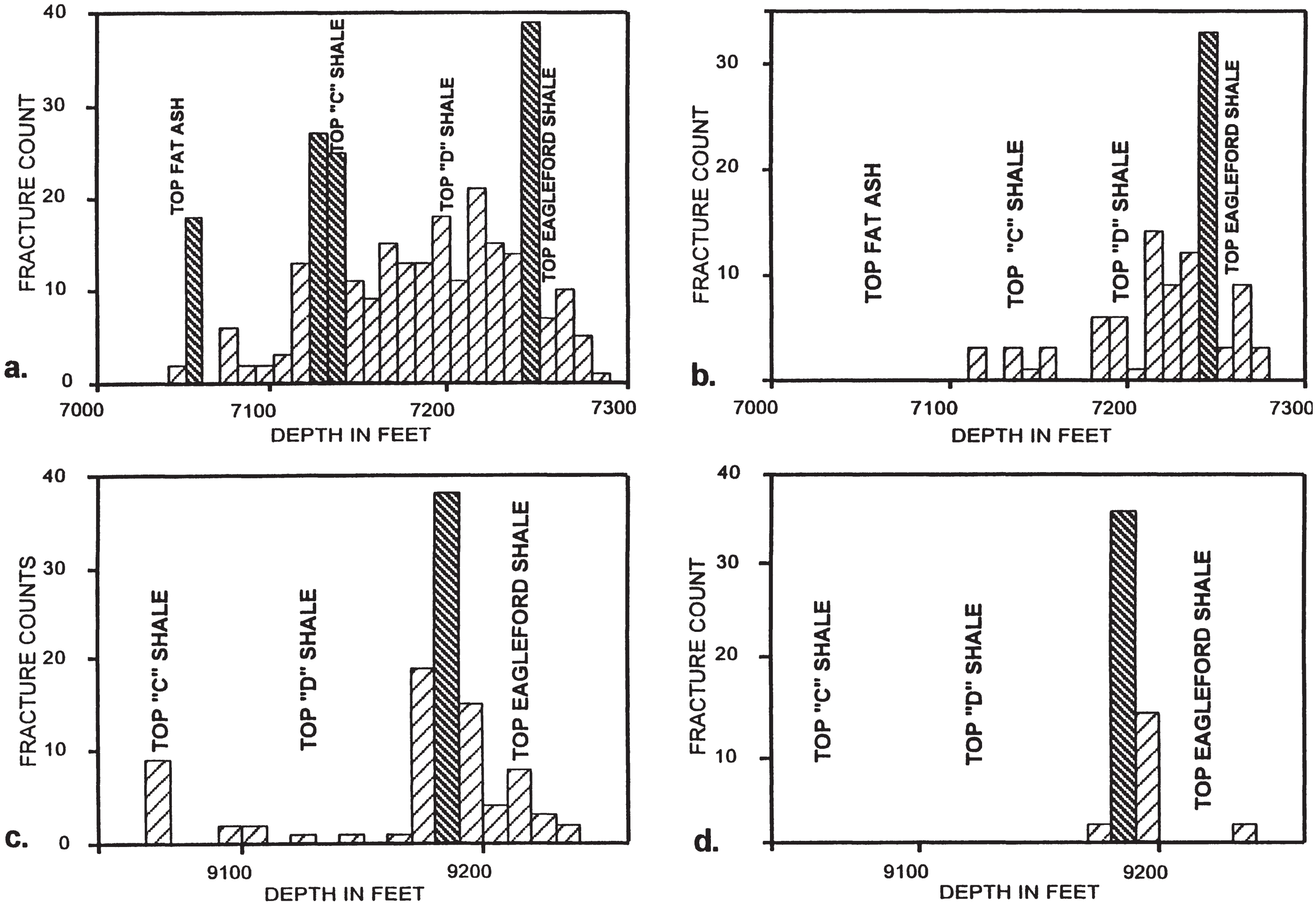

Figure 4. Fracture distributions in oriented cores from the Bell-Sample No. 1 and Robinson-Troell No. 1 wells: (a) Bell-Sample all fractures, (b) Bell-Sample oil-filled fractures, (c) Robinson-Troell all fractures, (d) Robinson-Troell oil-filled fractures.