Integrated Modeling Workflow for an Explicit Representation of the Fracture Network: Present Limitations and Perspectives

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Fractured reservoirs which produce only from fracture corridors require a deterministic fault network characterization in order to model equivalent properties at field scale, forecast flow behavior of those large conductive features and optimize a development plan, maximizing productivity while delaying watercut. Modeling of the main structural heterogeneities with respect to the fluid flow behavior is a key issue which requires integration of geophysical, geological and production results early. Also the higher the resolution for fractures both in wells and in seismic the better the 3D characterization, and the applicability of high-tech modeling software. A pluridisciplinary approach is an asset but software tools have difficulties handling multiple scales and simplification is required: • Outcrop analogs add value to the understanding of the field characteristics if the tectonic history and setting are similar. • Specific DST derivative slopes characterizing large conductive objects also provide essential but limited additional information such as distance to well and magnitude of the flow parameters. The two complementary types: • Genetic models, which aim at predicting the fracture network distribution and properties at field scale from the stress field and the rock mechanical properties, • Stochastic models, such as DFN, (which honor data observed at wells, field average behaviors and trends but have limited capability in predicting fracture occurrence and flow behavior at local scale, especially for large objects such as fault or fracture corridors), are reviewed showing their pitfalls in the light of the integrated workflow constraint up to the test simulation to validate equivalent flow properties of the DFN scenarios. Perspectives are proposed in the framework of integration of data at all scales coming from both static and dynamic sources.

Production Heterogeneity in Naturally Fractured Reservoirs: Data from Fort Liard

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The Fort Liard Gas Field in Northern Canada is a classic example of a naturally fractured reservoir and its history, along with that of the fields surrounding it, provides uncommon insight into the nature and behavior of fractured reservoirs. Fort Liard consists of an uplifted thrust complex of hydrothermally dolomitized Middle Devonian carbonates. The initial two wells on the structure, drilled in the early 1980's, each encountered very thin pay intervals, very low average porosities, and had disappointing gas deliverabilities. The field remained undeveloped until the late 1990's when Chevron drilled two very prolific wells into the structure. Recognition of the field as a naturally fractured reservoir was the key step in transforming it from a banished field to a news-headline maker.

Near Fort Liard are two structurally analogous NFR fields that produce from the same reservoir formation. Although outwardly similar, the three fields display distinctly different characteristics when it comes to the production performance of the fracture network. Importantly, and due largely to the interplay of development strategy and the fractured nature of the reservoirs, Fort Liard was an economic success, whilst its analogues produced very poor financial results. This paper will examine the relationship between fracture networks and production performance at Fort Liard and the surrounding fields as it is expressed at the field, well, and producing zone levels, with emphasis on the very high degree of heterogeneity expressed in the region.

Distribution and Properties of Syndepositional Faults and Fractures in the Compaction-Modified Capitan Carbonate Platform; Texas and New Mexico, USA

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The Upper Permian Capitan carbonate platform is cut by syndepositional faults and fractures. These parallel the platform margin and are clustered within strata that steepen and thicken abruptly into the basin; a pattern attributed to early compaction-induced deformation of the platform. Faults typically pinch out below growth monoclines. Therefore, although faults and fractures are probably below seismic resolution, their existence and distribution in the subsurface could be reliably predicted from identification on seismic of (i) divergent strata and (ii) growth monoclines.

Faults and fractures were repeatedly exploited by karst, leading to the replacement of the primary fault and fracture rocks with sediments. Two karst phases are discussed. The syndepositional KARST 1, associated with virtually all syndepositional faults and fractures, is filled by carbonate, siliciclastic and mixed sediments derived from the platform. The proportion and penetration depth of siliciclastics increases shelfward, as a result of the more frequent and prolonged exposure of the inner parts of the basinward-inclined platform during sea-level lowstands. The burial KARST 2, filed by coarse Cretaceous siliciclastics, is limited to the outermost 1 km of the platform, where the youngest syndepositional faults and fractures have penetrated the shelf top. The connectivity of faults and fractures to overlying stratigraphy is considered to have controlled the distribution of KARST 2.

Fault and fracture properties, which are here related to karst and depositional processes rather than structure, size or displacement, are thus to some extent predictable, as is also their distribution in the subsurface. Consequently, implications for underground fluid flow can be made.

Verifiable Predictions of Fractured Reservoir Attributes

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Networks of natural, opening-mode fractures are examples of seismically transparent deformation that can have a significant impact on fluid flow. Both geostatistical and geomechanical approaches have been used to characterize natural fractures, but only geomechanical models can be truly predictive, particularly for exploration purposes. The modeling goal is to incorporate as much relevant physics as possible in order to capture the range of property variation for a given locality and geologic history. Models to date typically make the relatively simple assumptions of elastic behavior and time-invariant properties, even though the diagenetic and burial history for many rocks implies changing mechanical properties that may take on different rheologic characters at different stages of lithification. Fracture modelers often assume rock has a diagenetic history up to the time of fracturing, fracturing occurs under conditions of relatively constant properties, and then additional diagenesis may occur after fracturing to plug up the flow pathways. We present evidence that contemporaneous with propagation of fractures significant diagenetic changes in the rock can fundamentally alter the outcome of the fracturing event itself. We also show that uinderstanding links between mechanical and chemical processes can help overcome limitations of conventional fracture sampling permitting model prdictions to be verified.

Influence of Regional Strain Variations on Fracture Development in Reservoir Rocks, Amadeus Basin Central Australia

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Fold-related and regional fractures occur in Ordovician sandstone reservoirs of Mereenie and Palm Valley fields in the Amadeus Basin fold thrust belt, Central Australia. Palm Valley gas field in the east of the basin is a type 2 fractured reservoir where an interconnected fracture network controls production in low permeability rocks (~0.1 mD). In Mereenie field in the basin's west matrix permeability (~10 mD) and porosity (~8%) are higher; fractures assist production (type 3 fractured reservoir). To model distribution and intensity of fractures we use structural restoration with strain capture in combination with curvature analysis. Results confirm dramatically differing fracture distributions between the Palm Valley structure formed by a low strain four-way-dipping detachment fold and the Mereenie anticline formed by a cylindrical, fault related fold.

The amount of foreland sedimentation and the spacing of regional fracture swarms correlates with lateral variations in orogenic strain. Orogenic shortening was about 13km in the west of the basin at the longitude of the Mereenie field. The spacing of regional fracture swarms is ~ 1500-2000 with ~3 km thick foreland sediments. Orogenic shortening at the longitude of Palm Valley in the east of the basin was ~33 km. The spacing of regional fracture swarms is ~300-500m with ~9km thick foreland sediments.

Thrust related strain intensity influences the development of both regional fractures and the flexural loading reflected in the thickness of foreland sediments. Thickness distribution of foreland sediments critically influences thrust-related fold styles which in turn control fold-related fracture systems.