

Platform-Margin Trajectory as a Control on Neptunian Dike Distributions, Devonian Reef Complexes, Canning Basin, Western Australia

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Syn depositional opening-mode fractures known as neptunian dikes are a ubiquitous feature of early-cemented platform-margins and are recognized in many carbonate systems throughout the geologic record. The Canning Basin's Devonian reef complexes preserve perhaps some of the world's best examples of these features. Neptunian dikes exert a strong influence on diagenetic patterns and permeability distributions; understanding the controls on their distribution is critical to accurate reservoir prediction and characterization.

Mechanisms proposed for the generation of neptunian dikes include: differential compaction of underlying sediments, compaction over basement structure, slope bedding-plane slippage, coeval faulting, gravitational instability, and seismicity. Which mechanisms control syn depositional fracturing depends largely on platform-margin trajectory, with fundamental differences in dike distribution, orientation, and extension observed between retrograding and prograding platform-margins.

In the retrograding platform-margins of the Frasnian southwest Oscar Range syn depositional fracturing is most intense in the reef/reef-flat, and decreases only subtly into the platform interior. Dike orientations run parallel and orthogonal to regional structural features, often intersecting the platform-margin at high angles, suggesting that compaction over basement topography and Devonian fault movement (e.g. Djowi Fault) were the dominant controls on syn depositional fracturing.

Fracture patterns observed in the prograding Famennian Barnett Spring platform are fundamentally different than those of the southwest Oscar Range. In Barnett Spring neptunian dikes primarily run parallel and orthogonal to the platform-margin (not regional structure) and are best developed in the reef/reef-flat, with fracture intensity decreasing dramatically towards the platform interior. These prograding margins consistently show double the amount of extension observed in the retrograding Frasnian margins.

Testing Geomechanical Models of Deformation Associated with an Evolving Reef Margin, Capitan System (Permian), Guadalupe Mountains, Texas and New Mexico, U.S.A

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Stratal geometries of folded rocks can provide constraints for the prediction of fracture distribution and density in the subsurface. In this study, we use stratal geometries and facies specific rock properties as input for geomechanical models. The models simulate deformation associated with the sequential development of a prograding/aggrading carbonate reef complex. Our attention is focused on the Capitan reef system (Permian), Guadalupe Mountains, Texas and New Mexico, USA. The models are based on the postulate that the geometry (Saller, 1996; Longley, 1999) and growth faults (Hunt et al., 2002) of the near back-reef "fall-in" beds record a sequential record of compaction-driven down-warping of the reef margin. Results are presented from forward models of reef deformation. Starting stratal geometries for the forward models are obtained from idealized reef-perpendicular cross-sections found in the literature (e.g. Harris and Saller, 1999). Target geometries for the deformed state are constrained by field surveys of sequence boundaries and a high resolution digital elevation model of the study area. Strain and stress concentrations obtained from model runs are compared with field observations of fault and fracture occurrence. While this work focuses specifically on the Capitan margin, geomechanical models such as ours should be applicable to the general reef margin case where one has access to a two- or three-dimensional facies characterization and a conceptual model for reef growth.

Fracture Characterization of Malampaya Field, Offshore Northwest Philippines

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Malampaya field produces gas from an isolated Oligocene-Miocene carbonate buildup (Nido Fm.) located offshore North-West Palawan, the Philippines. Proved reserves are approximately 2.6 Tscf. This carbonate reservoir exhibits matrix properties ranging from low to high porosity and permeability ($\phi < 5\%$, $k_{matrix} < 0.01\text{mD}$ to $\phi > 35\%$, $k_{matrix} > 1000\text{mD}$). Natural fractures, which are present throughout the reservoir, were studied as part of an overall reservoir characterization effort for the purpose of flow-simulation modeling.

Fractures were interpreted mainly from FMI logs and lost circulation data. A majority of fractures are open, steeply dipping, and their predominant strike orientation is NW-SE. They are dominantly extension fractures of tectonic origin. A minority of fractures are interpreted to be effective for fluid flow based on lost-circulation events. Faults are rare, of small displacement, and none are interpreted to be effective for fluid transport in the flow simulations. Rock matrix properties appear to play a major role in controlling fracture occurrence; low-porosity rock is more fracture-prone than high-porosity rock, hence some strata defined as "baffles" based on matrix properties may have high vertical permeability due to fractures.

Neural net software was used to distribute effective-fracture density (fracture surface area per unit volume rock) throughout the upscaled simulation grid, and this model was then used as soft control for SGS CoCok interpolation. Variables selected for neural net prediction are matrix porosity, petrophysical rock type, and stratigraphic layer. Grid cell effective-permeability tensors were computed using Chevron-proprietary software.

This abstract is based on Chevron work and may not reflect the Operator's view.

Relationship between Active Deformation, Stress Heterogeneity, and Fracture Permeability in the Suban Gas Field of South Sumatra, Indonesia

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Suban Field is located in the actively deforming South Sumatra basin. The field's most productive elements are fractured igneous and metamorphic rocks and overlying carbonates. The complex architecture of Suban was unraveled using PSTM and PSDM seismic volumes. The structure is a composite of Paleogene extensional elements modified by Neogene contraction to produce basement-rooted forced folds on one flank and shallowly-detached fault-propagation folds on the other.

Well test, wellbore image, and drilling data were integrated into a geomechanical framework to develop a stress and fracture characterization. Regionally SHmax trends NE but areas of the field show significant variation such that SHmax trends NW, paralleling local structural grain. We interpret these stress rotations to result from outer arc extension in active folds and/or the result of coseismic stress relaxation.

Natural fractures were differentiated into hydraulic classes based on reconciliation of petrophysical character with drilling, well test, and other petrophysical data. DFN models were constructed to characterize the fractures in their correct spatial framework. Field-wide the spacing of all fractures varies from 0.45 to 1.52 frac/m. The spacing of fluid-conductive fractures is an order of magnitude less. Undifferentiated, fracture density has no relationship to well productivity while the density of the largest fluid-conductive fractures is strongly correlative. Fluid-conductive fractures occur mainly in fault damage zones and domains of tight folding but their productivity is most clearly controlled by the interaction of stress and local structural elements. The vast majority of fluid-productive fractures occur in an envelope that trends 60° around SHmax.

Fracture Characterization and Geological Modeling of the Darajat Geothermal Field, West Java, Indonesia

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Darajat is a vapor dominated geothermal field located in West Java, Indonesia. The world's highest-performing geothermal well is located in Darajat with a production of 40 MWh. The Darajat field has energy-equivalent reserves in the order of 300MM BOE.

Geological setting

Darajat is a volcano-hosted system situated along the Sunda-Banda volcanic island arc. The volcanic reservoir exhibits a complex, non-layer cake distribution, with very low porosity and permeability intrusives and extrusives (andesite, microdiorite and basalt-andesitic lavas), and higher porosity pyroclastics (tuff, lapillistone, and breccias).

Fracture characterization

Quantitative fracture characterization used image log data from 18 wells and continuous core. Two main sets of steeply dipping (55°-80°) fractures predominate in the reservoir. The first set strikes mainly SE-NW (140°-320°) and the second WSW-ENE (070°-250°). Fracture control on well productivity (from PLT logs) and well connectivity (from interference tests) was incorporated in the reservoir simulation model through reservoir permeability variograms.

Fracture density (fracture surface area per rock volume), fracture porosity and other parameters were computed for each well. Fracture density varies from 0.001 frac/ft to 5 frac/ft. Although the reservoir is distinctly non-layer cake the fracture density distribution shows a consistent depth-related variation, and high fracture density zone occurs between 500-1200 m elevation (1500-4000 ft). This suggests a lack of lithological control on the fracture density distribution. Variograms describing the observed vertical density distribution, lateral connectivity and pseudo permeability have been used to populate a Gocad simulation sgrid with the calculated fracture properties.

Variation of Three Phase Relative Permeability in Fractured Reservoirs in Relation with Time

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Measurements of three phases relative permeability at reservoir condition is time consuming and expensive, however it is necessary for improving the oil recovery. During measurement of this parameter in carbonate rock plugs; with unsteady state method it was observed that the displacement time affects the curvature of relative permeability with long time displacement, the curvature will become linear and with short time displacement more curvature is in directed in fracture medium. These experiments show that mass transfer between phases has the main role in changing the curvatures. with high speed displacement liquids are adhere on the solid surface and the gas is passing from narrower trajectory, then relative permeability is reduced. In low speed displacement mass transfer phenomena effects the swelling and this cause increase in liquid mobility on the solid surface. Also, the pathway of passing gas is increased and relative permeability is increased by the time.

A New Technology for the Characterization of Microfractured Reservoirs (Test Case: Unayzah Reservoir, Wudayhi Field, Saudi Arabia)

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This paper presents a test-case of a new technology using artificially-enhanced, magnetic susceptibility anisotropy (referred to here as EAMS) for the characterization of microfractured reservoirs. The study covers the Unayzah gas

reservoir, in the Wudayhi Field, Saudi Arabia. Well tests indicate that fractures provide an important contribution to the productivity of the lower part of the Unayzah (Unayzah-B/C). The majority of the observed open fractures in this reservoir are small, in the order of microns to 10s of cm. Therefore an efficient and effective method is required to characterize these micro-fractures and to determine their contribution to porosity and permeability. A conventional geological characterization is costly, time consuming, and difficult to quantify in terms of assessing fracture impact on porosity and permeability. The EAMS technology, developed and tested here presents a rapid technology that "bridges" reservoir geology and engineering.

Verification of the EAMS method shows its superior accuracy in detecting fractures, compared to using thin sections of the same sample. The results show that EAMS-derived microfracture fabric strikes at ENE-WSW, consistent with that obtained by geological means. The effective-porosity profile obtained from EAMS tests is similar to that of the conventionally acquired porosity. Open microfractures in tested samples increase reservoir effective porosity by 30% to 48% in Unayzah B/C. The occurrence of connected microfractures is estimated to cause an increase in average permeability of 75% in Unayzah-B/C. Maximum permeability trend of NE-SW with total permeability anisotropy is detected. This will impact our operational and simulation effort directly.