Present-Day Stress in Sedimentary Basins: Insights from 20 Years of the World Stress Map Project

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The World Stress Map (WSM) Project has, since 1986, compiled a free and public global database of over 16000 quality-ranked present-day stress indicators. This global database provides fundamental insights into the state and origin of present-day stress in the crust and, in particular, has revealed that the plate-scale present-day stress field is primarily controlled by plate boundary forces. However, petroleum geomechanics applications, such as wellbore stability and hydraulic fracture stimulation, require knowledge of the present-day stress at smaller basin- and field-scales. The WSM database contains stress information from approximately 70 sedimentary basins worldwide, allowing a unique examination of the controls on stresses in the oil patch. Whilst some sedimentary basins exhibit roughly uniform stress fields (e.g. the Western Canada Basin, Northern North Sea), many others exhibit numerous regional and local variations in stress orientation (e.g. Central North Sea, North German Basin, Baram Delta Province, Permian Basin). Basin- and field-scale stress fields result from the complex combination of numerous factors including far-field forces (e.g. plate boundary forces), basin geometry (e.g. the shape of deltaic wedges), geological structures (e.g. diapirs, faults), mechanical contrasts (e.g. evaporites, overpressured shales, detachment zones), topography and deglaciation.

Porosity Versus Depth Relationship Derived from Rock Mechanical Arguments

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During formation of sedimentary rocks, the porosity is gradually reduced as a result of the increasing weight of the overburden. Prior to diagenetic processes, the porosity at a given depth depends on the rock composition – which is defined during sedimentation, as well as stress and pore pressure and rock mechanical properties – which change gradually during the burial process. The relationship between porosity and depth in a sedimentary basin has been derived on the basis of simplified assumptions about stress-paths and rock compressibility, in combination with a published empirical relation between mean grain size and sea-floor porosity and a simple assumption relating mean grain size to clay content. The porosity-depth relation is tested on a set of published data (Yang and Aplin, 2004: Petroleum Geoscience, 10, 153-162). They estimated several parameters, including porosity, pore pressure and clay content, from well logs for four different wells, making use of neural network methods. Our results show a good match between the theoretical relation and the log derived porosities, even when only two free parameters (related to rock mechanical properties) are used to fit the data for all four wells. The results indicate that the parameter relationships generated by the neural network to a large extent agree with the theoretically based relations derived here. This supports the validity of the physics used to derive these relations. The relations provide a foundation for practical estimation of pore pressures and the rock mechanical parameters involved.

Factors Influencing Whether Induced Hydraulic Fractures Cross Pre-Existing Discontinuities

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Hydraulic fractures are generally modelled as simple, planar, tensile fractures that propagate away from the wellbore in a plane that is perpendicular to the minimum principal stress. A hydraulic fracture mine through experiment at Northparkes, carried out in a naturally fractured rock, documented fracture branching and offsetting interactions. As the hydraulic fracture approaches pre-existing discontinuities it may dilate the discontinuity or form a new fracture on the other side of the discontinuity. Therefore the induced fractures have a more complex shape than predicted by planar models. We have studied the interaction of hydraulically induced/pre-existing fractures in our laboratory to help in designing effective hydraulic fracturing jobs.

Existing criteria that are used to predict whether or not the hydraulic fracture will cross the pre-existing discontinuity are based on simplified stress distributions on the interface and require information difficult to obtain (Blanton) or were developed using non-hydraulic loading (Renshaw and Pollard).

Our laboratory and theoretical study was conducted to extend Renshaw and Pollard's and Blanton's work. Fluid viscosity effects were considered, as they were shown to play a significant role at the beginning of the interaction and have been postulated to be important in crossing mechanics.

Our experiments were designed to produce fracture growth in regimes dominated by either viscous dissipation or by rock fracture toughness. The results show that the higher fluid viscosity in a medium-low permeable environment resulted in fracture propagation through the pre-existing discontinuities that were not crossed when a low-viscosity fluid was used.

Soil Gas Sampling to Verify Geomechanical Probability of Fault Reactivation

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There is much evidence to suggest that recently reactivated faults act as permeable conduits for fluid flow. Soil gas sampling over faults which propagate to the near surface has been proposed as a method of verifying the migration of fluid along faults. Such fluid migration can test the geomechanical methodology used to

determine the likelihood of fault reactivation. The likelihood of fault reactivation is assessed by determining the present day stress field from drilling data, constructing a 3D model of the pre-existing faults and establishing the mechanical properties of the fault rocks in the area. This data is used to determine relative fault stability of differently oriented faults according to the Griffith-Coulomb failure criteria. Sediments in the Port Campbell Embayment in the eastern Otway Basin are highly faulted and traps in the area host several CO_2-rich gas accumulations The Port Campbell Embayment thus provides an ideal location to study potential fluid (CO_2) migration along faults. Seismic interpretation of the area indicates that the Boggy-Creek and Buttress CO_2-rich accumulations are bound by faults which extend near to the surface. The relative likelihood of fault reactivation is high for these faults. Sixty-seven gas samples were collected in the vicinity of the faults bounding the Boggy-Creek and Buttress accumulations. The background concentration of CO_2 was determined to be 300-1000 ppm, with concentrations above this regarded as anomalously high. Seventy-five percent of anomalously high samples were associated with the surface locations of the faults. This finding suggests that these faults are acting as conduits for the flow of fluid (CO_2). However, isotopic analysis suggests that the CO_2 detected at the surface may be from a shallower source than the Buttress and Boggy-Creek CO_2 accumulations.

Rock Strength Determination from Well Logs: A Review

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Accurate knowledge of rock strength is essential for in situ stress and wellbore stability analysis and prediction of solid production. Quantitative data on rock strength can only be obtained from cores. However, in most cases the core strength database will be limited, discontinuous and often biased toward stronger reservoir intervals and rarely available in non-reservoir sections where most of instability problems occur. Consequently, rock strength evaluation is primarily based on log strength indicators, calibrated where possible against core measurements. There are many published log-core strength correlations that can be used to develop a rock strength model. These empirical relationships are developed for specific rock types and their application to other rocks needs to be verified before they are utilized.

Applicability of about 45 empirical rock strength models is summarized and compared with an extensive rock strength core database from hydrocarbon wells around the world including several wells from Australia and South East Asia region. While some equations work reasonably well, rock strength variations with individual rock property show considerable scatter, indicating that most of the empirical models are not sufficiently generic to fit all the data in the database. Although rock strength estimation can be improved by multi-variable analysis, this requires additional logs and petrophysical interpretation that may not always be available, particularly during exploration and appraisal stages.

Field examples illustrate the application of novel computing techniques, such as fuzzy logic and genetic algorithms, which optimise and improve the strength estimation, are compared to commonly used empirical rock strength models.

Effect of Pore Pressure on Laminated and Homogenous Rocks Permeability under Hydrostatic and Triaxial Loading

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Accurate knowledge of reservoir physical properties such as permeability is crucial for accurate prediction of reservoir performance. Single-phase permeability measurement is normally performed at hydrostatic external loading. Reservoir rocks are subjected to stress anisotropy and tectonic movements thus in-situ stress state is non-hydrostatic.

Pore pressure decreases or increases with production or injection operations result in an increase or decrease in the net effective stress exerted on the rock mass. This in turn causes permeability to be a dynamic property throughout the reservoir life. Experimental work was performed on laminated (lamination parallel to flow direction) and homogenous sandstone rock samples to investigate the effect of pore pressure variation on absolute rock permeability when subjected to hydrostatic and triaxial stress state conditions. Experimental results of all tested rock samples indicate that permeability tends to decrease as pore pressure decreases for both hydrostatic and triaxial stress conditions. Permeability reduction is much more pronounced when rock samples are subjected to external triaxial stress compared to that obtained under hydrostatic stress loading. The permeability reduction occurs early on the reservoir depletion process in low permeability laminated rocks while it occurs at very late stage in high and low permeability homogenous rock samples. These observations indicate that permeability is stress type dependent and that permeability- external pressure state- Internal pore pressure relationship is mainly affected by rock microstructures.

The Origin of Overpressure in the Carnarvon Basin, Western Australia from Porosity-Effective Stress Analysis

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Porosity-effective stress analysis of 37 normally and overpressured wells in the Carnarvon Basin, Australia, identified 12 wells with overpressure generated by disequilibrium compaction, and four wells with overpressure generated by fluid expansion. Disequilibrium compaction is the dominant overpressure-generating mechanism in wells along the Rankin Trend as far South as Gorgon 1 and Spar 1. Fluid expansion is the dominant mechanism of overpressure generation in wells along the Barrow Trend and around the Alpha Arch. Disequilibrium compaction-generated overpressures occur, as would be expected, where the Tertiary sediment thickness is greatest and fluid expansion overpressures where the Tertiary is thinnest. Indeed where the N-1 (35 Ma) reflector is greater than ~1500 m below seabed disequilibrium compaction overpressure are observed and where it is shallower than ~1500 m fluid expansion overpressures are observed. Log-based pore pressure detection using Eaton's (1972) method on p-wave acoustic data yielded the most accurate estimates with an exponent of three where the overpressure was generated by disequilibrium compaction, and an exponent of six where the overpressure was generated by fluid expansion.

Predicting and Updating Geopressure 1000 Feet Ahead of the Bit at the Wellsite

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Predrill pore pressure predictions are typically made for planning purposes using analog wells, seismic and or basin modeling. Once onsite, pore pressure estimation from steaming LWD data often deviates from this prediction. The pre drill prediction becomes suspect and is usually not referred to again. A fit for purpose basin modeling capability that runs on a PC and can be employed at the rig site enables the model to be updated as new information becomes available, continually extending the prediction of pore pressure to in excess of 1000 feet ahead of the bit. The model includes both compaction and internally generated pressures (hydrocarbon maturation, etc).

Examination of the first wells this system on which this capability was deployed reveals that over 40% of the predrill predictions held within one half a pound per gallon over the entire depth of the well. By applying this technique on site and updating the model as new data becomes available the accuracy of the predictions rose to over 80% for the first 1000 feet and over 60% within one half pound per gallon for greater depths. Selected cases (including some from Australia's MW shelf) are reviewed and lessons learned presented.

The biggest cause of inaccuracy of prediction is in the ability to estimate the depth at which particular stratigraphic sequences will be penetrated. This often results in a pressure ramp coming in higher or lower than anticipated, altering casing depths. Anticipating these modifications to the drilling plan reduces non productive time and increases rig safety.