Geomechanical analysis and Discrete Hydraulic Fracture Simulations to Improve Cardium Well Efficiency

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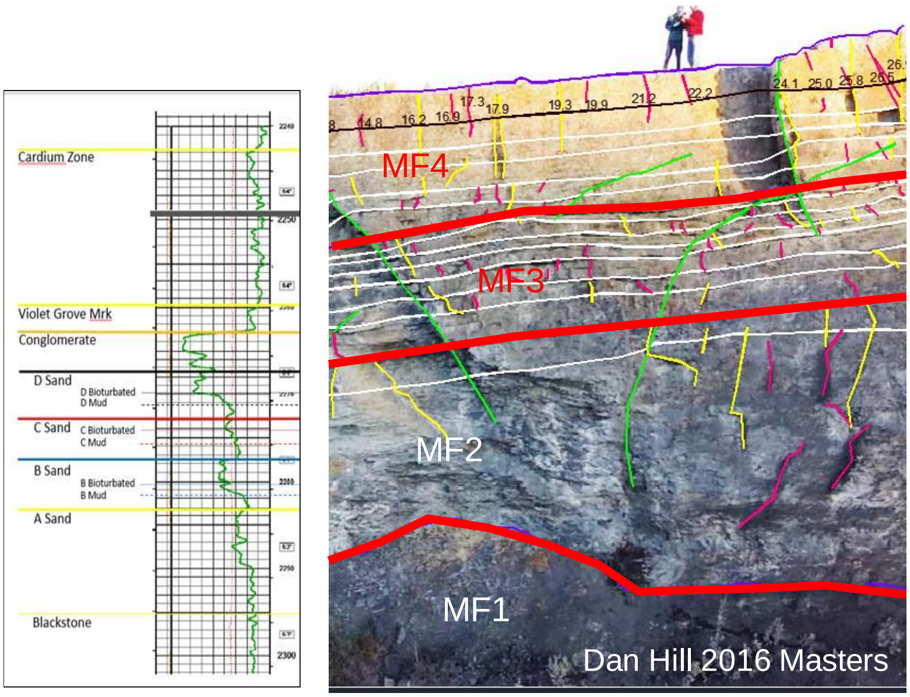
1.0 Introduction

The Cardium is a highly heterogeneous tight reservoir comprising multiple para-sequences of generally cleaning upward cycles of mudstone, bioturbated muds, interbedded muds and sands, sometimes unconformably capped by conglomerate. Within Obsidian's Crimson Field, there are 4 main cycles named from bottom up Cardium, A-D with most of the oil held within the B, C and D sands. Production within the Cardium is typically either from primary production or water flood. Primary production has dominantly been through the drilling of horizontal producer wells primarily within the B and C sands and oriented north/south or east/west. In the study area, a pilot program of ~SHmax NE/SW parallel drilled producers with a row of inclined water injector wells between each producer was being tested. The producers were completed through multi-stage hydraulic fracturing with almost well parallel fracs generated to create an effective drain and limit early water breakthrough. Overall well performance in the Cardium formation is strongly influenced by the complex interaction between geomechanics & stresses, the natural fracture system and well stimulations. To help identify some of the critical controls upon stimulation behaviour, the Golder-Ikon team set about a programme of review, analysis and modelling with a view to help optimise well orientation, landing depth, stimulation performance, initial production and sweep efficiency in order to improve economics. The key stages of the study were:

- Review of available data around the characterisation of the presence of a conductive natural fracture network
- Analysis of drilling behaviour, DFIT data and wireline log data in order to calibrate a Geomechanical Model derived from the distribution of elastic properties, Young's Modulus and Poisson's Ratio
- A campaign of diagnostic (backward) fracture modelling of well stimulation to help understand and isolate critical controls on current completion operations and observed well performance.
- A campaign of forward modelling of well stimulation to help identify better completion strategies that may result in improved out comes

2.0 Conceptual Structural Analysis & Modelling

Work by Hill 2016 including both extensive field work and well data, had established a reasonable conceptual geomechanical framework for the Cardium. This related each facies of the para-sequence, to a broad mechanical composition as well as some indicative natural fracture properties. This geomechanical facies framework provided the basis for all subsequent analysis as it represented a common reference point to relate all simulations to, as well as natural fracture observations Fig 1.



Facies (From Hill 2016)	Description
Litho-Facies/MF 4	Medium to thick bedded fine grained sandstone with little or no bioturbation
Litho-Facies/MF 3	Thin and very thinnly interbedded fine grained sandstone, siltstone and black mudstone with <30% bioturbation
Litho-Facies/MF 2	Bioturbated, finally inter-bedded mudstone, siltstone and fine grained sandstone with >30% bioturbation
Litho-facies/MF 1	Dark Grey Mudstones

Fig. 1. A type log for the Cardium showing the 4 cycles, A, B, C and D and the 4 mechanical facies present in each cycle, MF1, MF2. MF3. The outcrop picture illustrates the fracture architecture present (adapted from Hill 2016).

The Cardium can be a highly structured reservoir with the presence of both significant faults and an extensive fracture network being present at some locations which can provide significant permeability uplift as well as permeable pathways for early water breakthrough. At the location in question, whilst there were natural fractures seen on image logs, it was believed to be relatively structurally quiescent and major shear fractures and faulting were generally not thought to be present. However, the work of Hill had showed evidence of facies-controlled jointing, with his observations being used to develop a more modelling consistent conceptual fracture model of the likely distribution of structures present. This conceptual framework was then converted to a digital discrete fracture network (DFN) model, an explicit description of the likely natural structures, present within the Cardium. The key components within the DFN were:

- Each para-sequence has through going fractures broadly spaced
- Each top sand has unit scale fractures spaced at a function of bed height
- The length scale of structures is somewhat arbitrary (albeit reasonable) with the top sand fractures shorter than the para-sequence ones.
- Additionally, there were reactivated bedding shears, seen within the top sands.
- The orientation of structures was constrained from image logs and the length scale estimated from field evidence.

Whilst the fracture model does represent a "conceptual story", it does honour available data, fracture architecture concepts and structural geological principals, (Fig 2).

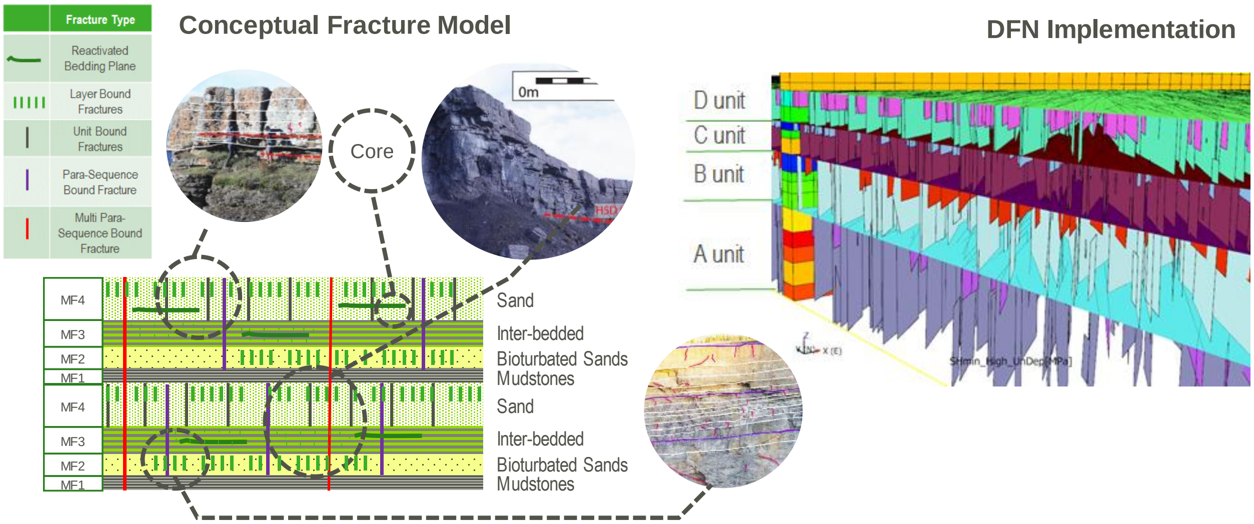


Fig. 2. Conversion of Hill 2016 field observations into a conceptual fracture framework and its conversion to a representative DFN model

3.0 Geomechanical Analysis & Modelling

The primary objective of the geomechanical analysis is to provide stress conditions to be applied to the DFN for hydraulic fracture simulation. This was achieved via the following applied workflow:

- Review available dataset and determine appropriate wells for 1D geomechanical analysis.
- Consider depleted and undepleted pore pressure cases.
- Derive stress models that reflect uncertainty of strain.
- Upscale 1D models to DFN resolution.
- Consider Fracture Initiation Pressure and Fracture Permeability within Cardium reservoir units.

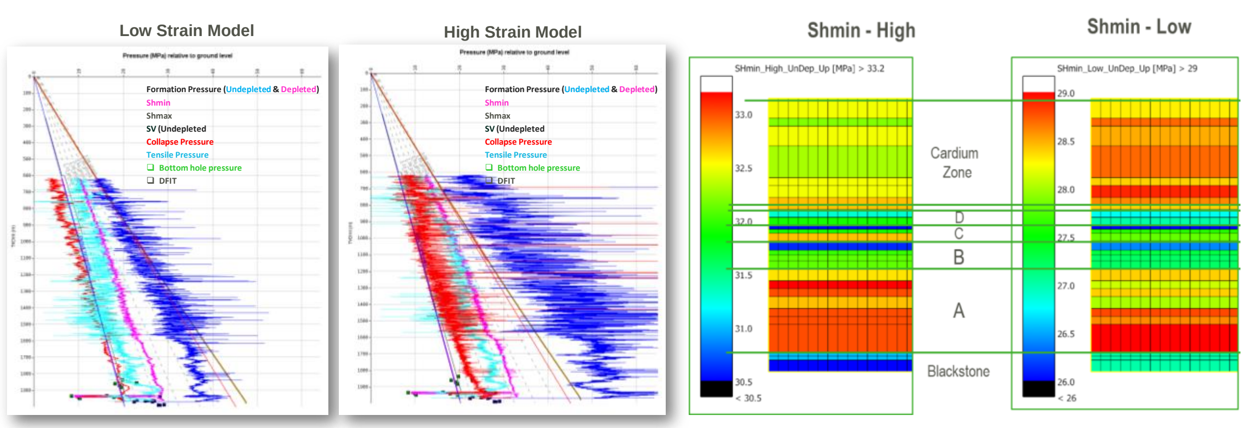


Fig. 3. Mechanical Earth Model (MEM) data for the equally plausible low strain and high strain cases and its conversion to an upscaled modeling framework

However, uncertain inputs and calibration of the geomechanical model leaves ambiguity with respect to relative magnitudes of the principal stresses, and in turn, the stress regime. Both an extensional (low strain model) and a strike slip (high strain model) satisfy available observations that includes breakout and DFIT (in situ stress tests) orientations in horizontal wells e.g. DFIT at top of hole and break outs at the side of hole.

The resultant mechanical stratigraphy (YM & PR) and principal stress magnitude logs for both end member regimes were subsequently upscaled to grid resolution for implementation within the FracMan hydraulic fracture model, Fig 3.

4.0 Discrete Hydraulic Fracture Simulations

Discrete Hydraulic Fracture Simulations were carried in the FracMan code (Dershowitz et al 2010) that uses a unique geomechanical scheme to allow hydraulic fractures to grow and interact with natural structures in a highly efficient manner (Rogers et al 2010, Rogers et al 2014). The objective is to identify the optimum of injection layer that results in the greatest stimulated fracture area, comprising a combination of both hydraulic fracture and natural fracture area. As a simple sense check on the initial models, they were compared again reported stimulation from the Cardium where each frac was imaged with microseismic data, Duhault 2012, Fig 4. This showed that the frac lengths, complexities and general cloud shape of the actual and simulated fracs were very consistent

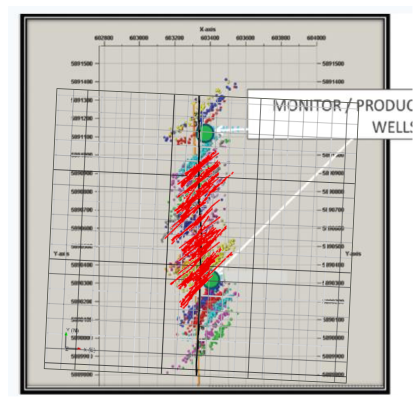


*Fig 4: Comparison between simulated and actual (*Duhault 2012) *Cardium microseismicity*

Having established the reasonableness of the simulation approach, a large number of simulations were conducted where the injection layer was varied through the modelling grid, stimulating different mechanical facies within different cycles and calculating the resultant stimulated area/volume.

This was carried for both the high and low stress conditions. Depending upon the combination stresses, elastic properties and the presence of natural fractures, the length, height and complexity of different stimulations was varied. One of the most effective ways of displaying the results was the injection-propagation matrix, which shows which layers will be stimulated depending upon which injection layer, Fig 5. The more vertical the array, the better the injection layer.

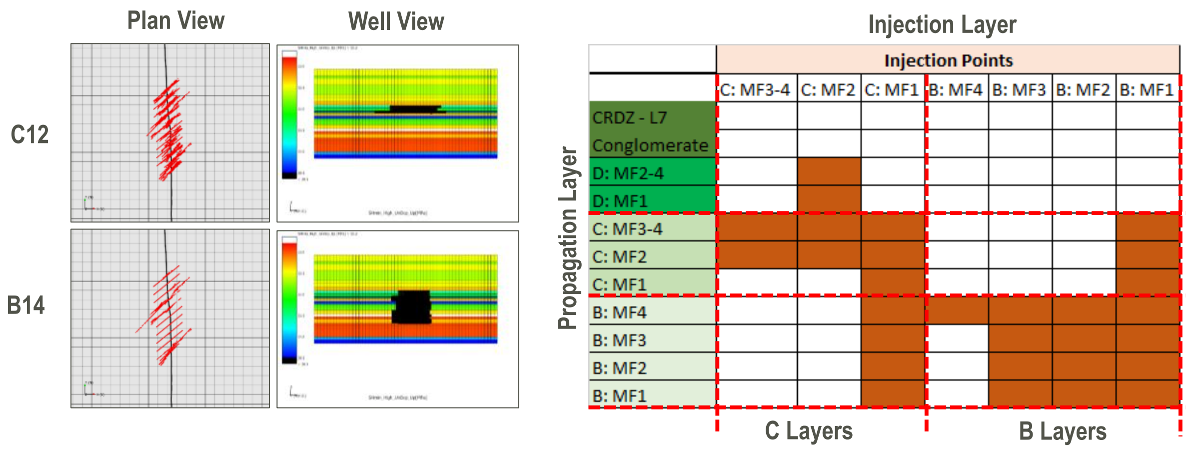


Fig. 5. Plan view and well section for 2 injection cases (C12 & B14 layers) injecting into different layers within the B and C sands, showing the likely length and height of the stimulations and also the injection-propagation matrix for one of the stress cases. The Injection & propagation layers are labelled by Cardium cycle and mechanical facies (MF), see Fig1

All of these simulations were carried out on the current N-S well trajectory. With future wells being planned, there was an opportunity to evaluate whether an alternative well orientation, might provide improved stimulation efficiency. To investigate this, models were run for a horizontal section of the well, placed into key layers, with their orientation rotating from SHMAX parallel (0 degs), incrementally around to SHMAX perpendicular (90 degs). For each of these scenarios, the SRV in both 2D (area) and 3D (volume) was calculated and plotted against the relative well direction, Fig 6.

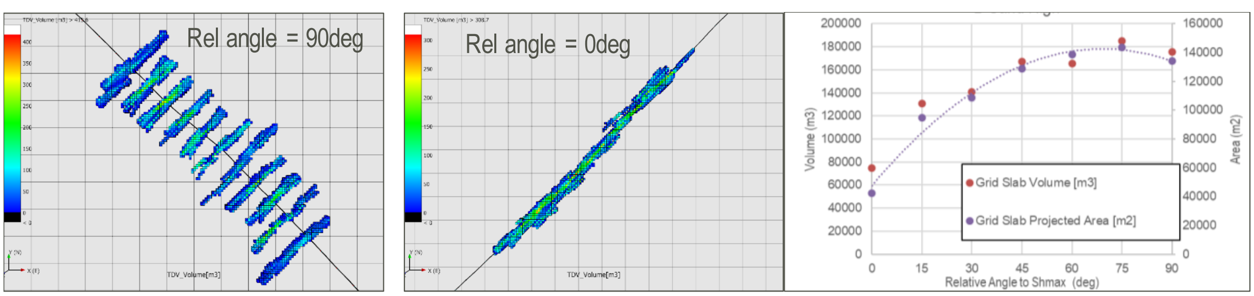


Fig. 6. Plan view of SRV results for 2 end member cases of well orientation expressed as well orientation relative to SHmax and graph showing 2D and 3D SRV results as a function of relative well angle.

What these results showed was that SRV could be optimized for either water flood or primary production by adjusting well orientation within the constraint of the well layouts. As Fig 6 shows small modifications of direction, can result in relatively large increases in connected area. Wells drilled following this study used this information to improve completion efficiency, plan interwell spacing, and plan future secondary recovery design. Many of these wells, showed a marked increase in production.

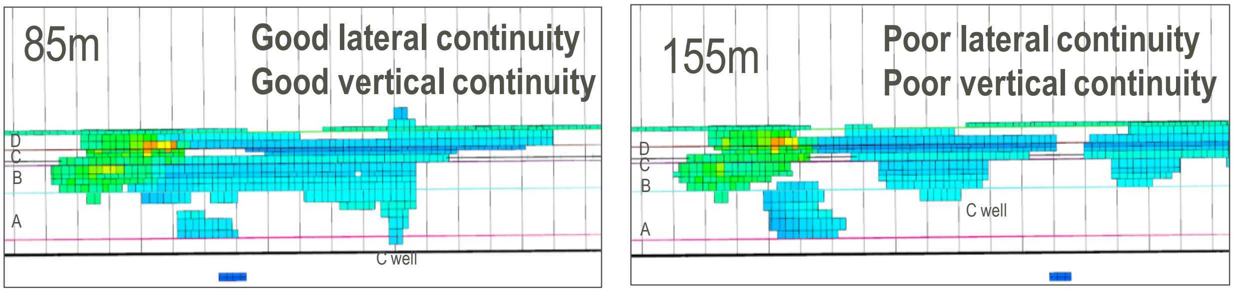


Fig. 7. Plan view and well section for 2 cases injecting into different layers within the B and C sands and the injection-propagation matrix for one of the stress cases

A further investigation of stimulation efficiency was an evaluation of the stage spacing on SHMAX parallel drilled wells. Simulations were carried out for a range of different stage spacings, and the interaction between each stimulation evaluated, by establishing the volume of reservoir where S3 was impacted. At closer spacings (85 m) the impacted S3 volume was shown to have good vertical and later continuity, particularly in the B and C sand layers. However, as the spacing increased, the resultant stimulation efficiency drops, with poor continuity, Fig 7.

5.0 Summary

Both the geomechanical and hydraulic fracture modelling showed that the Cardium system is complex with resultant stimulation effectiveness, highly sensitive to the injection layer due to stress and elastic property heterogeneity and natural fracture influences. Based directly on some of the findings of this study, implemented drilling pattern changes, resulted in all subsequent drilling programs having improved production rates. Importantly, the results of the study remained useful when the decision was made to change to primary production wells, where SRV rather than drain effectiveness is most important.

Acknowledgements

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