Development of a new approach for hydraulic fracturing in tight sand with pre-existing natural fractures

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APPEA Conference and Exhibition , 5 - 8 June 2016

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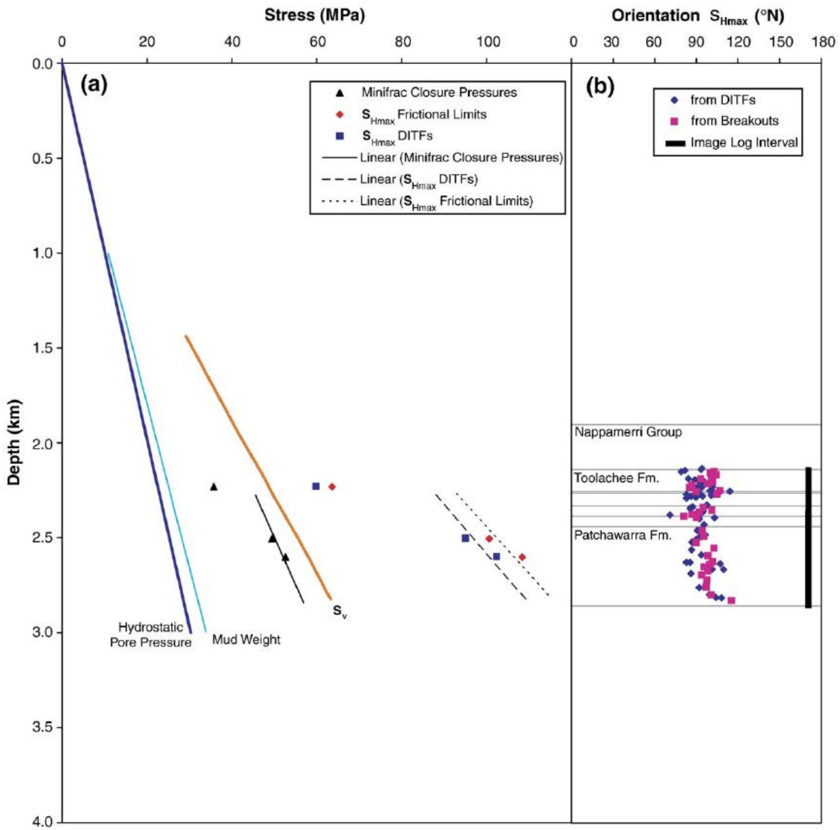
Introduction



Stress versus depth between Toolachee and Patchawarra formations in Cooper Basin (Reynolds et al, 2006)

- The existence of a complex stress regime where normal, strike-slip and reverse fault regimes exist.
- Complexity in fracture propagation, reducing effective proppant placement and leading to lower gas production.
- Highly complex stress regimes and pre-existing natural fractures can manifest near-wellbore pressure loss (NWBPL) and pressure dependent leakoff behaviour during fluid injection

(Johnson and Greenstreet, 2003)

Introduction

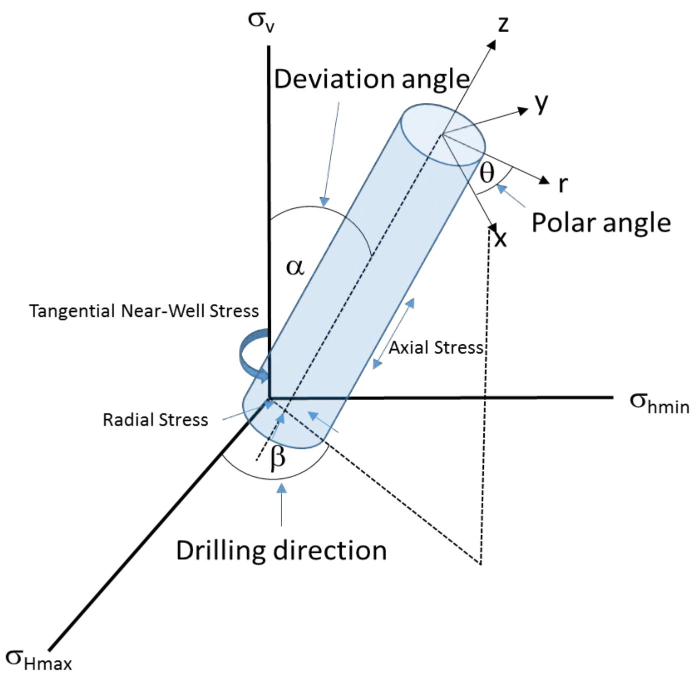
Optimise the hydraulic fracturing treatment in such a complicated system

- Drilling an inclined well perpendicular to natural fracture orientation
- Maximise the intersection between open natural fracture networks and induced hydraulic fractures (Murphy and Fehler, 1986).
- Drilling in strike-slip stress regimes at 55 –70° azimuth relative to the maximum horizontal stress (Bentley et al, 2013)

How to

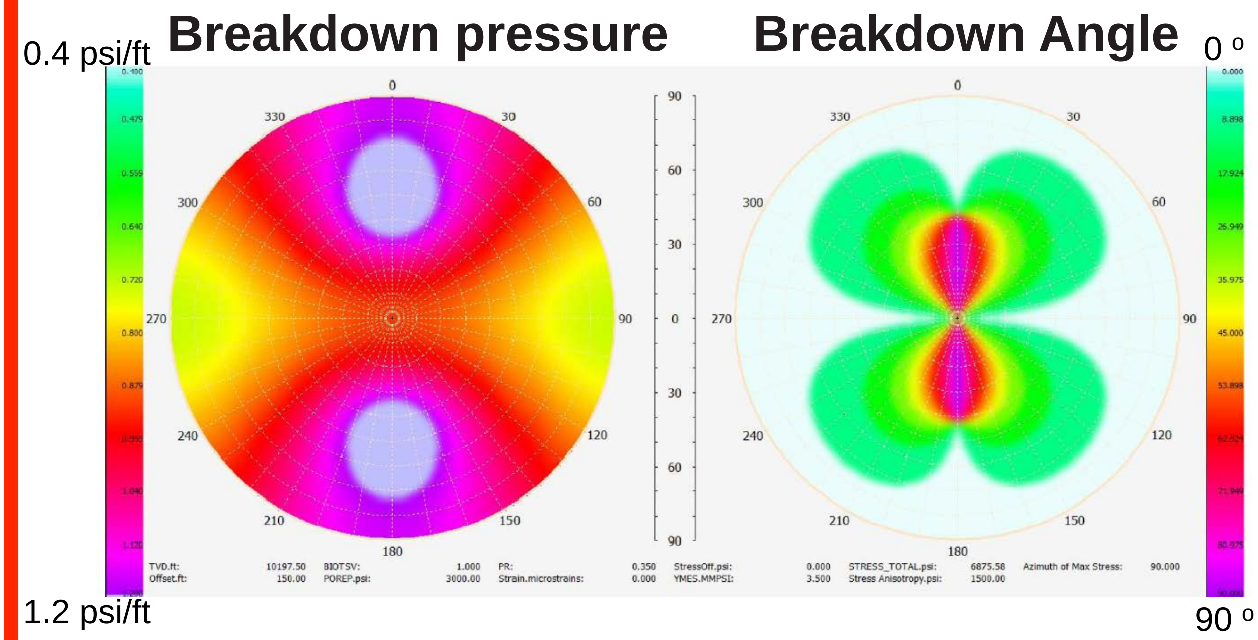
- Planar 3D hydraulic fracturing modelling
- Diagnostic fracture injection test (DFIT)
- Wellbore image log

Theoretical Background



The stress distribution around the wellbore (Kirsch, 1898)

The modified Kirsch equations transform the stress and shear stress along the wellbore axis



(Barree and Miskimins, 2015)

Theoretical Background

A complete suite of wireline logs

Calculated Values

$$\sigma_{hmin} = \frac{\nu}{1-\nu}(\sigma_v - \alpha_v p_p) + \frac{E}{1-\nu^2}\varepsilon_h + \frac{E\nu}{1-\nu^2}\varepsilon_H + \alpha_h p_p$$

$$\sigma_{Hmax} = \frac{\nu}{1-\nu}(\sigma_v - \alpha_v p_p) + \frac{E}{1-\nu^2}\varepsilon_H + \frac{E\nu}{1-\nu^2}\varepsilon_h + \alpha_h p_p$$

$$P_{Breakdown} \text{ or } P_{wb} = 3\sigma_{hmin} - \sigma_{Hmax} - P_{Pore} + T_0$$

$$P_{FissureOpening} \text{ or } P_{fo} = \frac{1}{2}(\sigma_{Hmax} + \sigma_{hmin}) + \frac{1}{2}(\sigma_{Hmax} - \sigma_{hmin})\cos 2\theta$$

Strains & Stresses

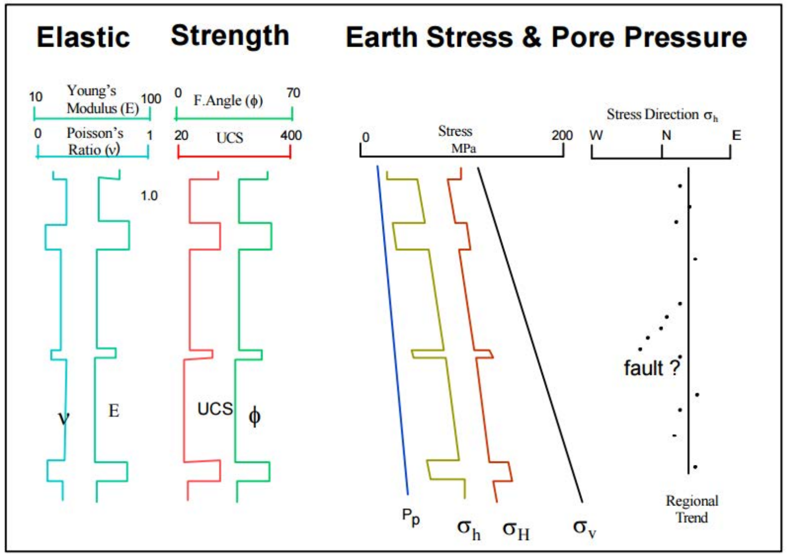
(Plumb et al. 2000 Zoback, 2007)

Observed Values

Diagnostic fracture injection test (DFIT)

DFIT data is analysed and “best fit” match is used for planning future stimulation work and determining reservoir characteristics

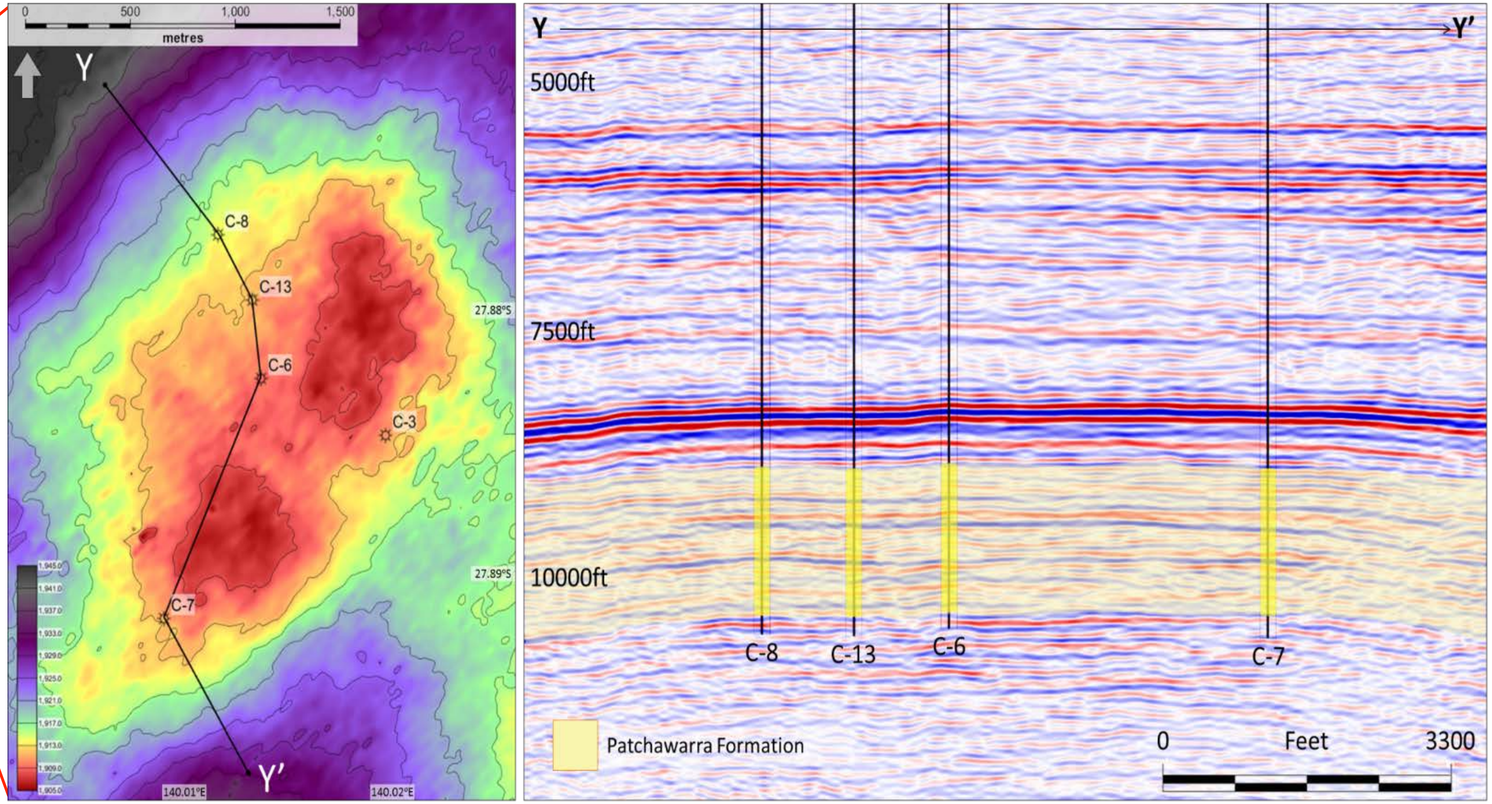
Schematic 1D Stress Profile



- **More Reliable Stress Profiling**
- **Stress Regime Categorization**

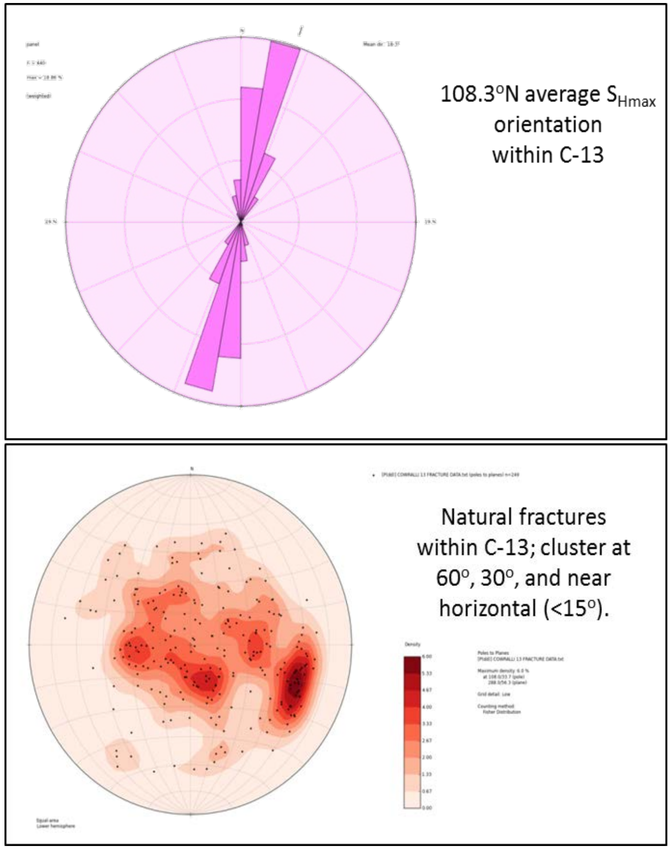
Case Study

The Cooper Basin
N-E South Australia



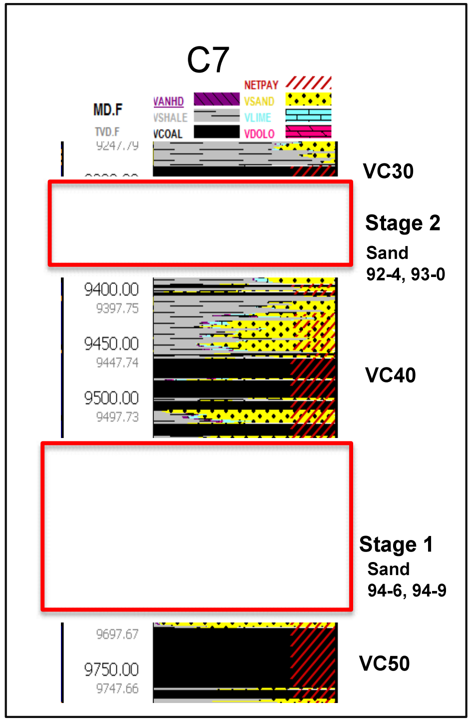
Structural map of the C-Field with a cross-section showing the Patchawarra Formation correlation across wells.

Case Study



Borehole breakout and natural fracture analysis

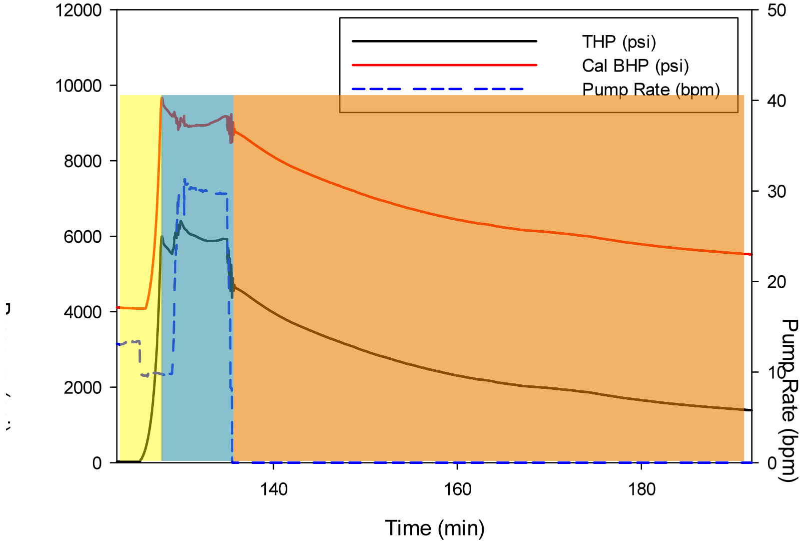
Hydraulic fracturing in Well C7



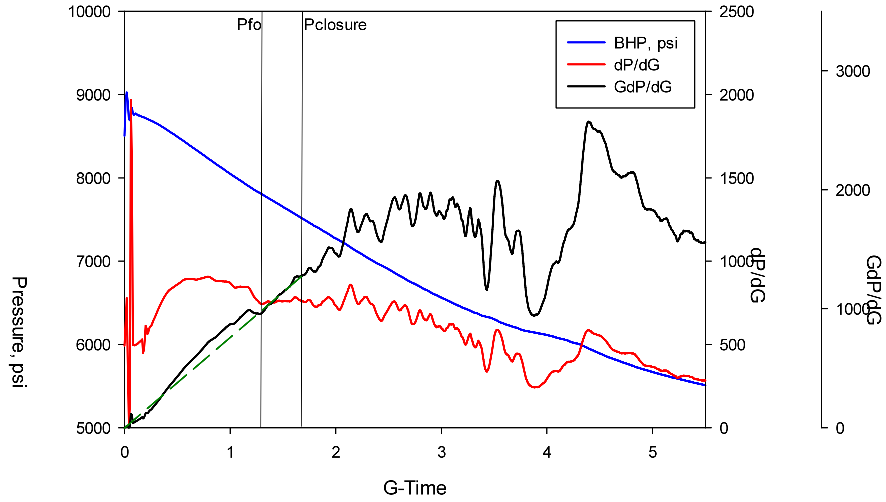
Well/stage	Depth	Net pay	Permeability	Porosity	Water saturation
C-7, stage 1	9,533–9,634 ft	70 ft	0.12 mD	11.3%	34%
C-7, stage 2	9,294–9,351 ft	36 ft	0.06 mD	10.0%	31%

Diagnostic Fracture Injection Test (DFIT)

Well C 7 Stage 1

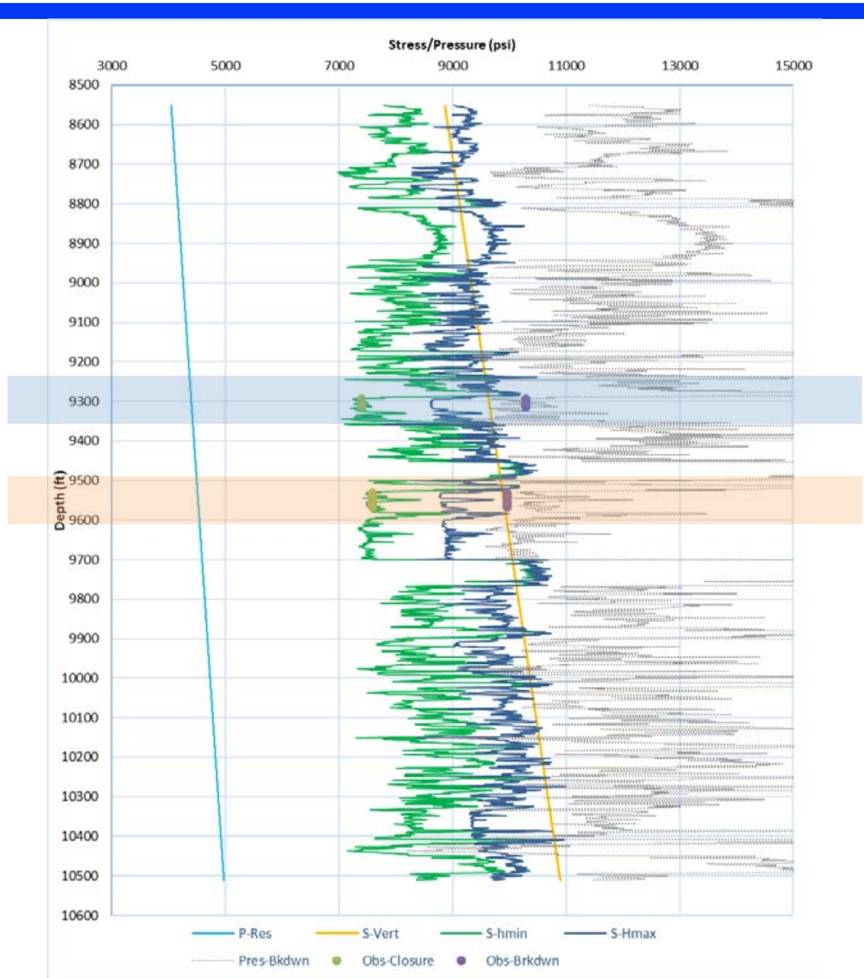


G- Function Analysis



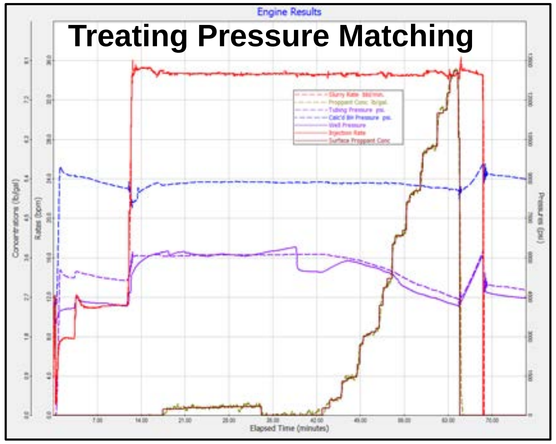
BCA results						
Well/stage	**Breakdown pressure (P_{wb})**	**ISIP**	**Closure pressure (P_c)**	**Fissure opening pressure (P_{fo})**	**Leakoff type**	**Pressure dependent leakoff (PDL) coefficient**
C-7, stage 1	9,962 psi	8,812 psi	7,596 psi	7,822 psi	PDL	0.005
C-7, stage 2	10,291 psi	8,528 psi	7,406 psi	8,064 psi	PDL and height recession	0.003

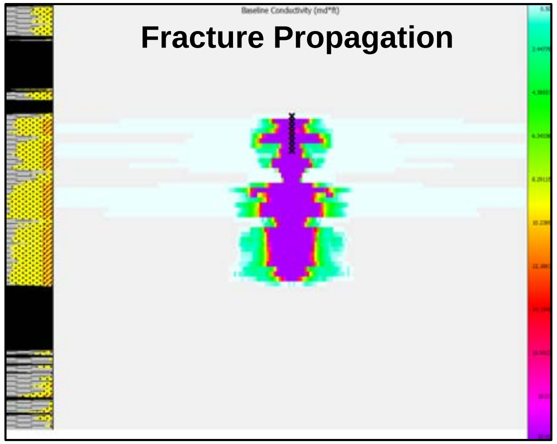
1D “Best-Fit” Stress Profile

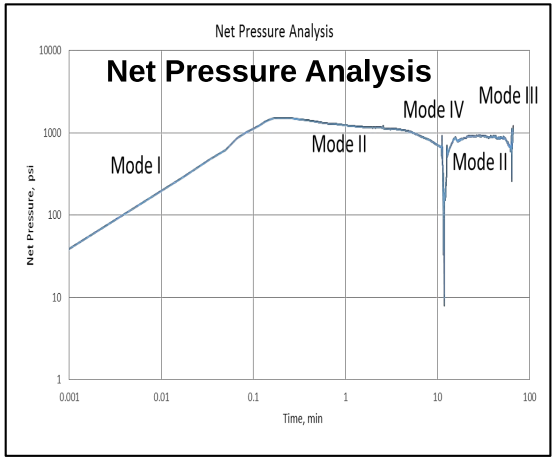


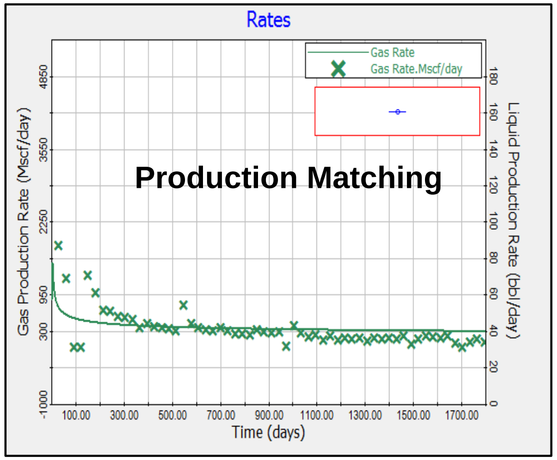
- “Best-fit” match between calculated and observed breakdown and closure values from DFIT in Stage 1 and 2
- Effective tectonic strain is 338 microstrains ($\varepsilon_{eff} = f(\varepsilon_{h\text{-}min}, \varepsilon_{H\text{-}Max}, \nu)$)
- The stress contrast at the boundary between sand and coal are 1200 psi
- The hydraulic fracturing propagation may also experience secondary containment as a result of stress regime or modulus changes

Hydraulic Fracture Simulation



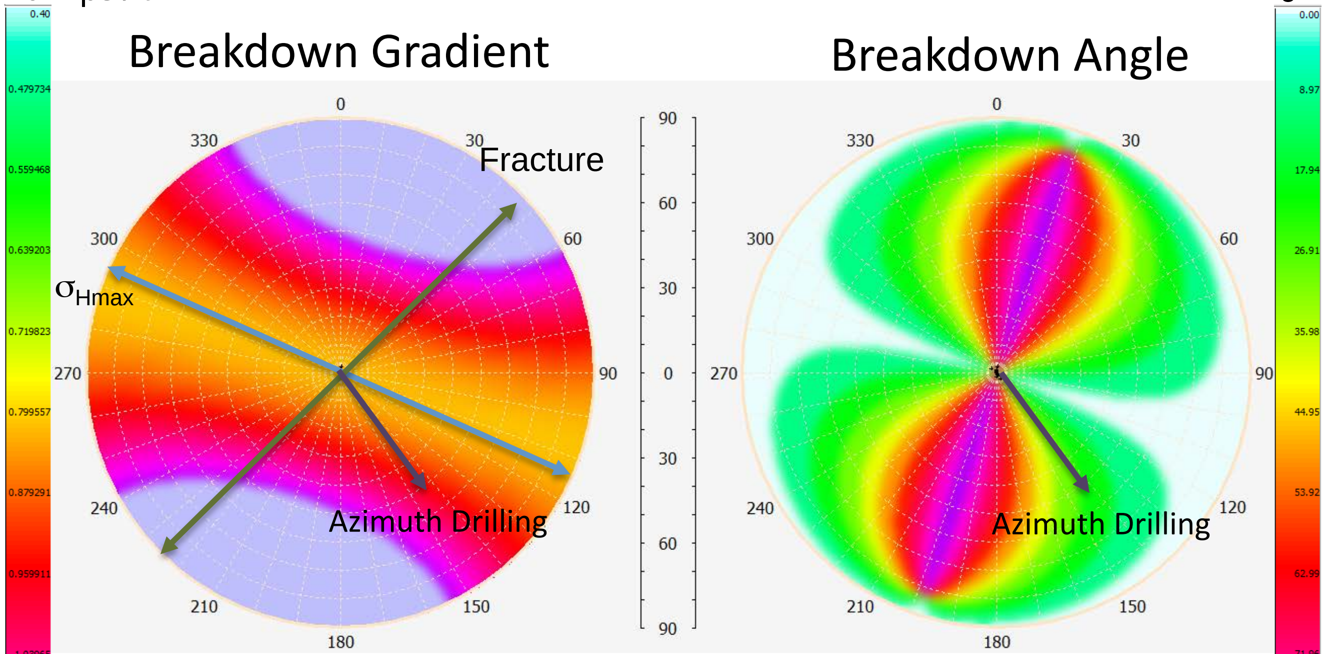






- Delayed borate crosslinked fluid was injected reached a bottom hole pressure of up to 9000 psi.
- 100 mesh sand was injected in order to reduce the NWBPL
- The fracture shows good height containment within the target formation with the average conductivity of 10 md.ft.
- Log-log plot of net pressure was observed the fracture was created in a confined area and the length growth remained within the target zone.
- Production matching was performed at the average gas production rate of 300 Mscf/day over 5 years

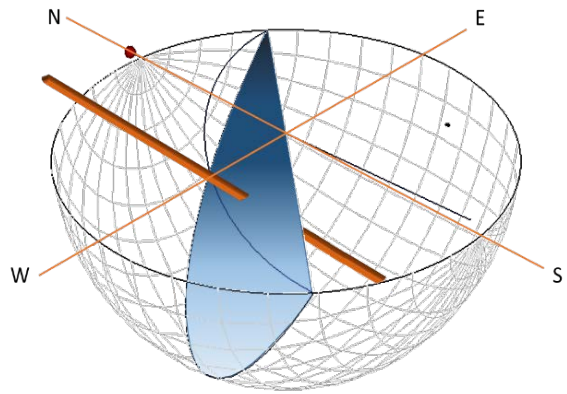
Fracture orientation and Well Design



Stress Conditions: Azimuth of σ_{Hmax} = 108 º ESE
Strike-slip fault stress regime ($\sigma_{Hmax} > \sigma_v > \sigma_{hmin}$)
Azimuth of natural fractures: 48º NE

1.2 psi/ft

90 º



Well Inclined Drilling (Azimuth 138 Degrees with Inclination 60 Degrees)

Conclusions

- A rigorous process of DFIT interpretation has been proposed, incorporating step down, before closure and after closure analysis methods.
- A “best fit” 1D stress profile has been presented for this case study in the Cooper Basin using the DFIT break down and closure values with image log data.
- The process used the stress profile in a planar 3D fracturing model to pressure history-match the hydraulic fracturing treatment with corresponding production history match
- A deviated well plan was developed to maximise hydraulic fracture interaction by striking a well perpendicular to the natural fracture orientation and at an inclination favourable for minimising fracture complexity
- In this case study area, the recommendation is for using a deviated and inclined wellbore with an azimuth of 138° and inclination of 60° to maximise natural fracture interaction and minimise opportunities for near-wellbore tortuosity effects
- A similar process could be used for other wells in high-stress strike-slip stress regimes using offset or pilot hole image log and DFIT data.

Acknowledgements

Co-authors

Manouchehr Haghighi Raymond (Ray) L. Johnson, Jr
David Kulikowski Dennis Cooke

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