Stress Evolution of Maari Field, NZ: Implications for Fault/Fracture Integrity, Stress Prediction, Infill Drilling, and Borehole Integrity*

Roderick W. Van Koughnet[1], David A. Castillo[2], and Vivek Paranjpe[1]

Search and Discovery Article #20442 (2018)**
Posted October 15, 2018

*Adapted from extended abstract prepared in conjunction with oral presentation given at 2018 AAPG Asia Pacific Region GTW, Pore Pressure & Geomechanics: From Exploration to Abandonment, Perth, Australia, June 6-7, 2018
 DOI:10.1306/20442vankoughnet2018

[1]OMV-NZ Ltd., Wellington, New Zealand (rod.vankoughnet@omv.com)
[2]Insight GeoMechanics Pty. Ltd., Perth, Australia

Abstract

Maari Field, offshore Taranaki Basin, NZ, is an oil field producing via horizontal wells from Miocene deep water turbidites of the Moki Formation (Figure 1). Maari has produced more than 35 MMSTB since initial development in 2009.

A 2014-2015 infill drilling program encountered greater than anticipated reservoir pressure depletion and more challenging mud losses while drilling than during initial field development. Currently, an additional infill drilling option is being evaluated and in order to reduce risk of repeating previous drilling challenges, geomechanics studies are being conducted to characterize the evolving stress-state of the field and to better understand root causes of past drilling difficulties. Ultimately, the objective of the current analysis is to make recommendations that should reduce risk for future infill drilling.

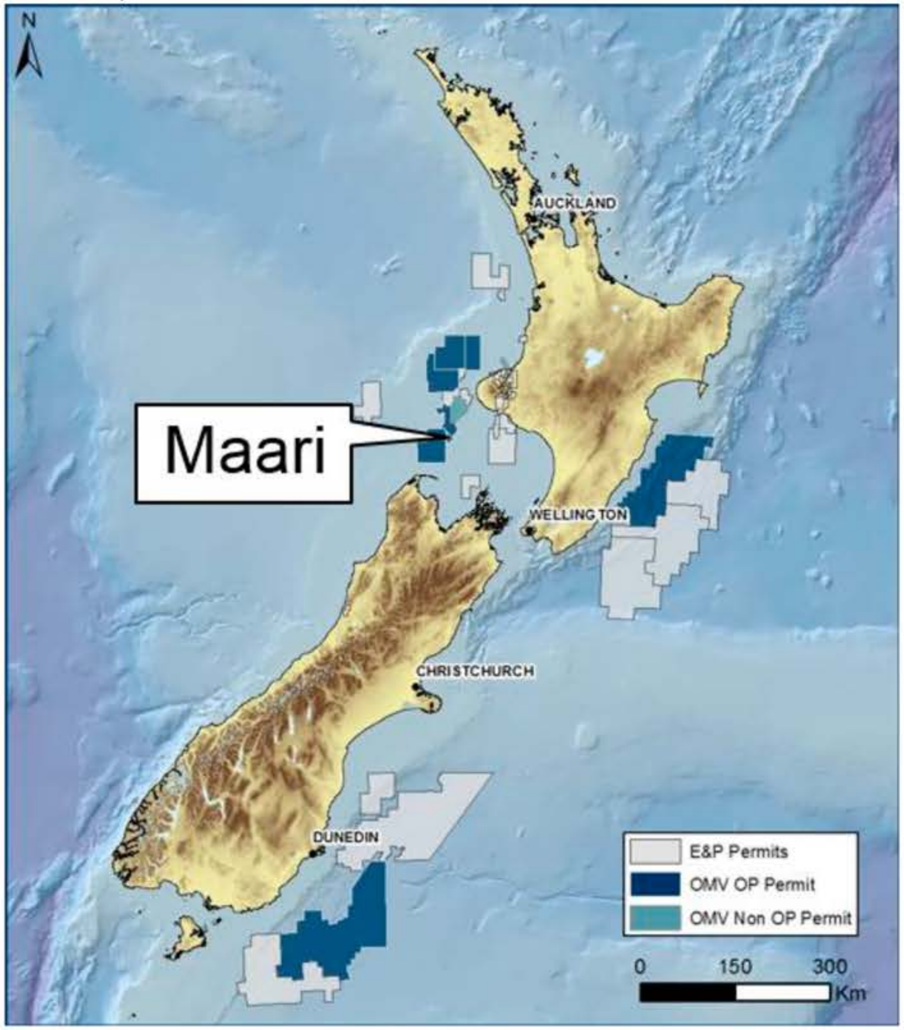
Recent secondary recovery water injection step rate tests (SRTs) have proven to be particularly useful in characterizing the time and pressure dependent stress state of Maari Field. Although Maari Field was initially developed with three inclined point-source water injection wells (Figure 1), these ultimately failed to maintain reservoir pressure in the field, which had become variably depleted by more than 1000 psi from initial hydrostatic conditions. The original water injection scheme envisaged simple layer-cake reservoir connectivity, supported by injection at pressures and rates sufficient to generate fractures in line with S_{Hmax} (N25°-44°E). Infill drilling in 2014, however, demonstrated significant pressure compartmentalization and poor pressure support. Additionally, current history-matched dynamic reservoir models can only account for about 70% of injected water volumes and it is surmised that the aggressive water injection could have destabilized nearby faults or fractures, which could have become pathways for losses of injected water. The original three injectors were abandoned and sidetracked to become infill oil producers in 2014. Also, in 2014, a watered out horizontal production well, MR1, on the west flank of the field was converted for use as a flank water injector and has been successful thus far at starting to restore reservoir pressure to at least two nearby production wells. Water injection in this well is designed to be conducted carefully at matrix conditions in order to initiate a flank water front that moves through the reservoir sands rather than fractures or faults. Injection pressure strategy is determined by six step rate injection tests conducted since 2014

at different ambient reservoir pressures (Figure 2). These tests have been used to define the production/injection-induced stress evolution of the horizontal stresses with Moki reservoir pore pressure changes in Maari Field (Figure 3).

For depleted reservoir conditions, S_{hmin} diverges significantly from the pure normal faulting frictional failure trend (standard fracture gradient calculation). Thus, SRT calibration of Stress Path becomes essential for predicting fracture gradient that can be encountered during infill drilling in depleted reservoirs. Because the stress path fracture gradient maintains a larger magnitude than the frictional faulting trend, drillers can be provided with a broader mud weight window (Figure 4). In addition to predicting S_{hmin} fracture gradient using stress path, we predict the natural fracture gradient, the stress at which an optimally oriented pre-existing fracture or fault will fail (also stress path dependent).

Understanding stress path evolution also helps decide which fault orientations could be most problematic through the life of the field. For original hydrostatic conditions at Maari (Table 1), vertical stress (S_V) is about the same magnitude as the maximum horizontal stress (S_{Hmax}) and both are greater than the minimum horizontal stress (S_{hmin}). This defines a transitional active stress regime comprised of both normal and strike-slip faults. 3D seismic data corroborates this, confirming two recently active fault sets, one normal and one strike-slip (Figure 5). During Maari stress evolution, S_V will likely remain constant. Both S_{Hmax} and S_{hmin} will diminish via the same stress path during depletion and increase with sufficient water injection (at least locally). For the depletion scenario, an inactive or non-critically-stressed normal faulting regime prevails ($S_V > S_{Hmax} > S_{hmin}$); although, S_{hmin} and S_{Hmax} decreases about 20% of the pore pressure change. For localized increases in pore pressure above hydrostatic due to water injection, the stress state returns to the original critically-stressed normal faulting regime, and later evolves to a critically-stressed transitional normal and strike-slip stress regime ($S_{Hmax} \sim S_V > S_{hmin}$) with further increase in pore pressure.

By characterizing the production/injection stress evolution of Maari Field through step rate injection testing, we were able to quantify the absolute magnitudes of the horizontal principal stresses, which provided new information to quantify the natural fracture gradient to avoid pressures that could destabilize faults and fractures while drilling through variably depleted reservoir compartments. For instance, step-rate injection operations at initial, depleted, and injection-charged conditions have documented a non-linear stress path that has become a predictive tool for quantifying S_{hmin} and S_{Hmax} stress magnitudes. It appears that the faults are likely to be relatively stable at depletion conditions. However, during injection operations, the stress state is such that active normal faulting and strike-slip faulting can be supported because injection pressures produces a critical stress state transitional between active normal faulting and active strikes-slip faulting. The implications of this stress-pressure evolution may likely impact drilling and reservoir modelling.



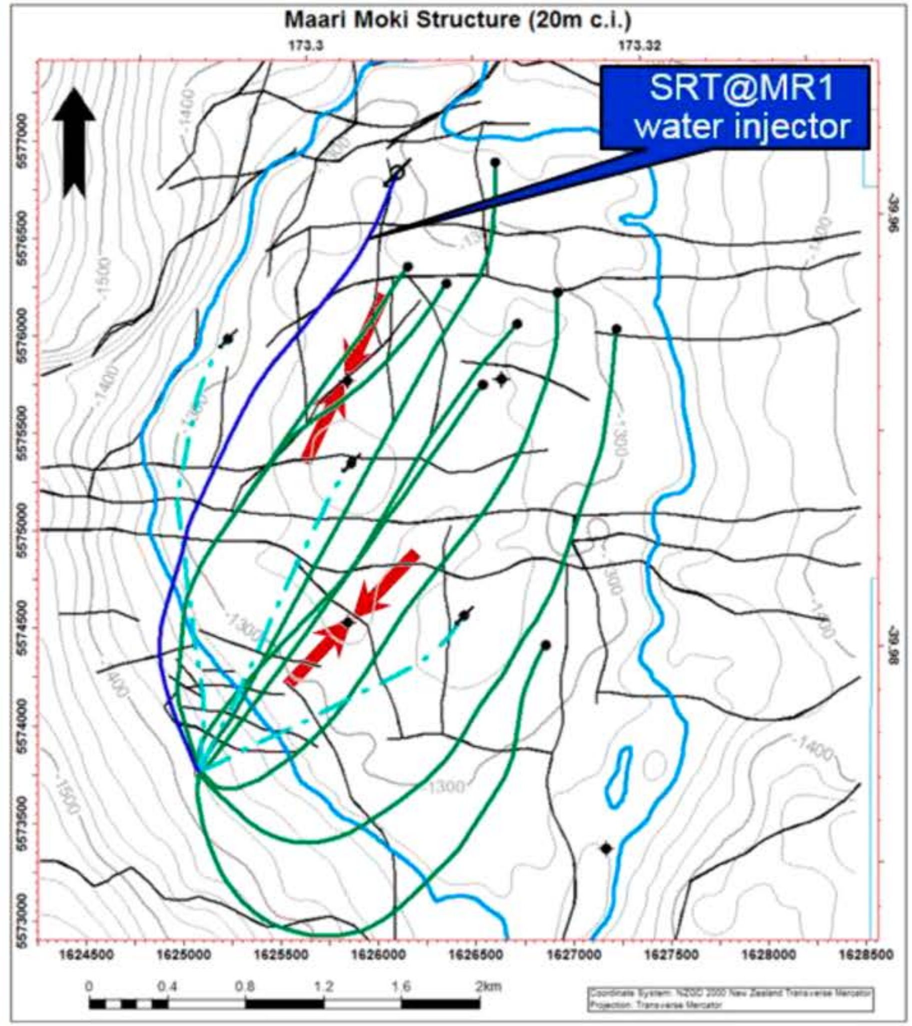


Figure 1. (Left) Location map for Maari Field, offshore Taranaki Basin, NZ. (Right) Maari structure on top Moki reservoir. Blue contour is original OWC, -1327mTVDss. Green wells are current Moki oil producers. Light blue dashed wells are original inclined (70°) water injectors, abandoned 2014. Dark blue well is current horizontal flank water injector, MR1, converted from production to injection 2014. SHmax direction is shown (red arrows) for Maari-1 (N25°E) and Maari-2 (N44°E) appraisal wells.

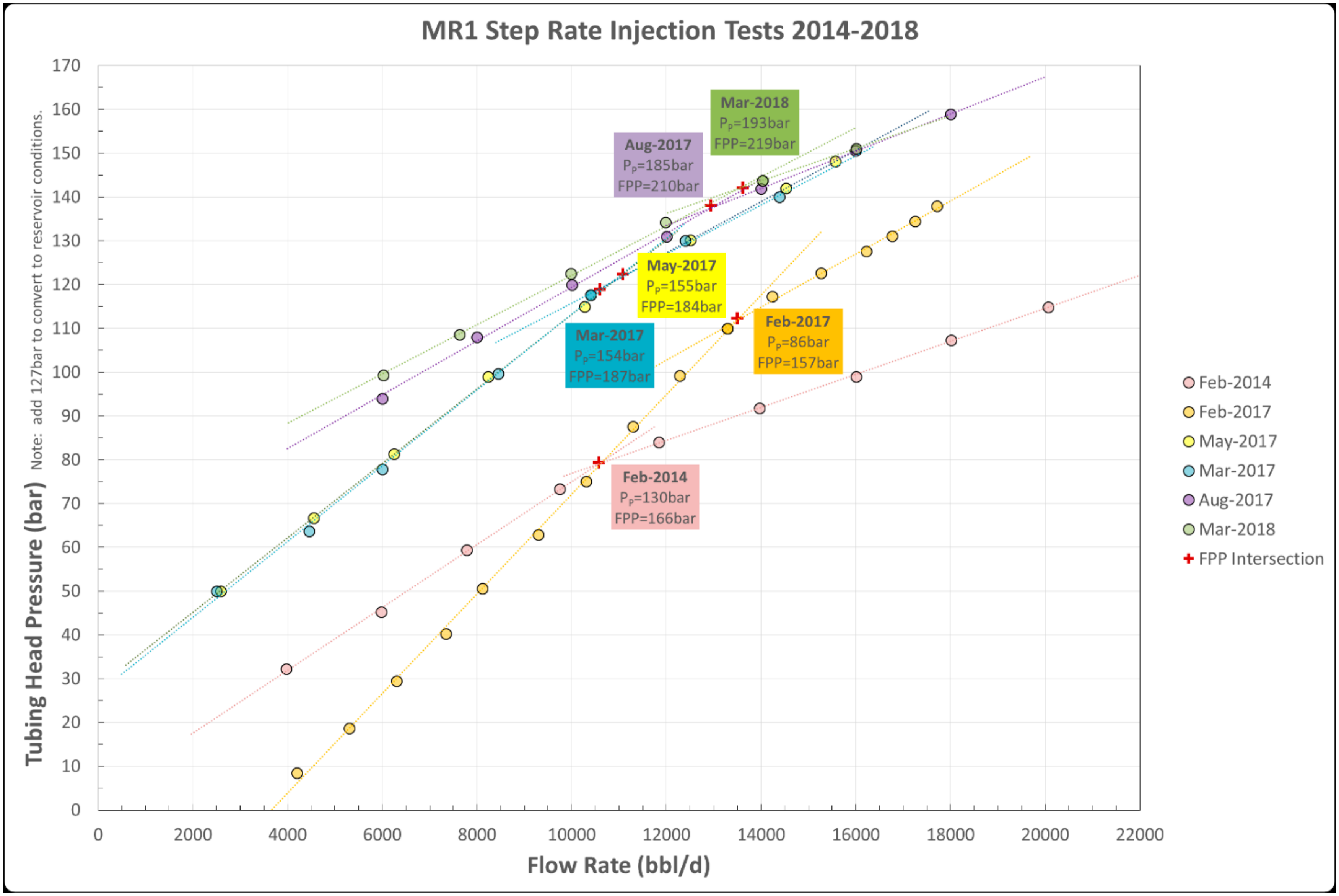


Figure 2. Pressure vs. flow rate plotted for six step rate injection tests (SRTs) on Maari MR1 injection well since 2014. In each test, a distinct break in slope is used to interpret formation parting pressure (FPP), which is determined by extrapolating the post-slope change trend back to zero rate. Because FPP is a measurement of Shmin, these tests are instrumental in defining how reservoir stresses change with pore pressure (PP). The February 2017 SRT (after 20-month injection hiatus) is most important for calibrating the stress conditions for depleted reservoir, while the 2014 SRT is closest to original hydrostatic conditions. All remaining SRTs are at over-pressured conditions.

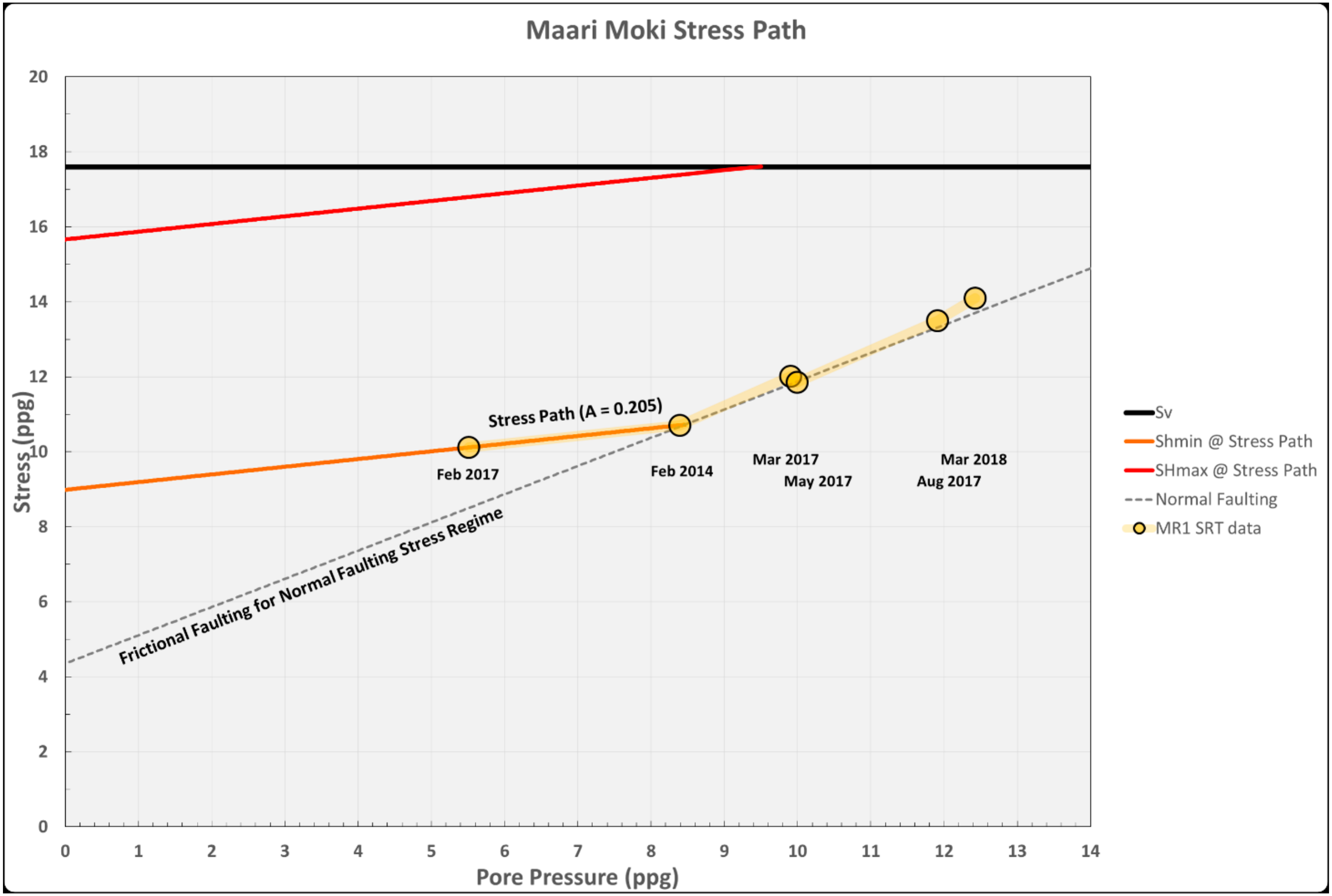


Figure 3. SRT interpretations of Shmin as a function of PP are plotted (orange points) as Stress vs. Pressure to illustrate Maari Stress Path (orange line) for the Moki reservoir. For PP > hydrostatic, Shmin plots near the Frictional Faulting failure line for pure Normal Faults. For PP < hydrostatic, Shmin follows the orange Stress Path trend. Calculated SHmax Stress Path is illustrated in red, with constant vertical stress in black.

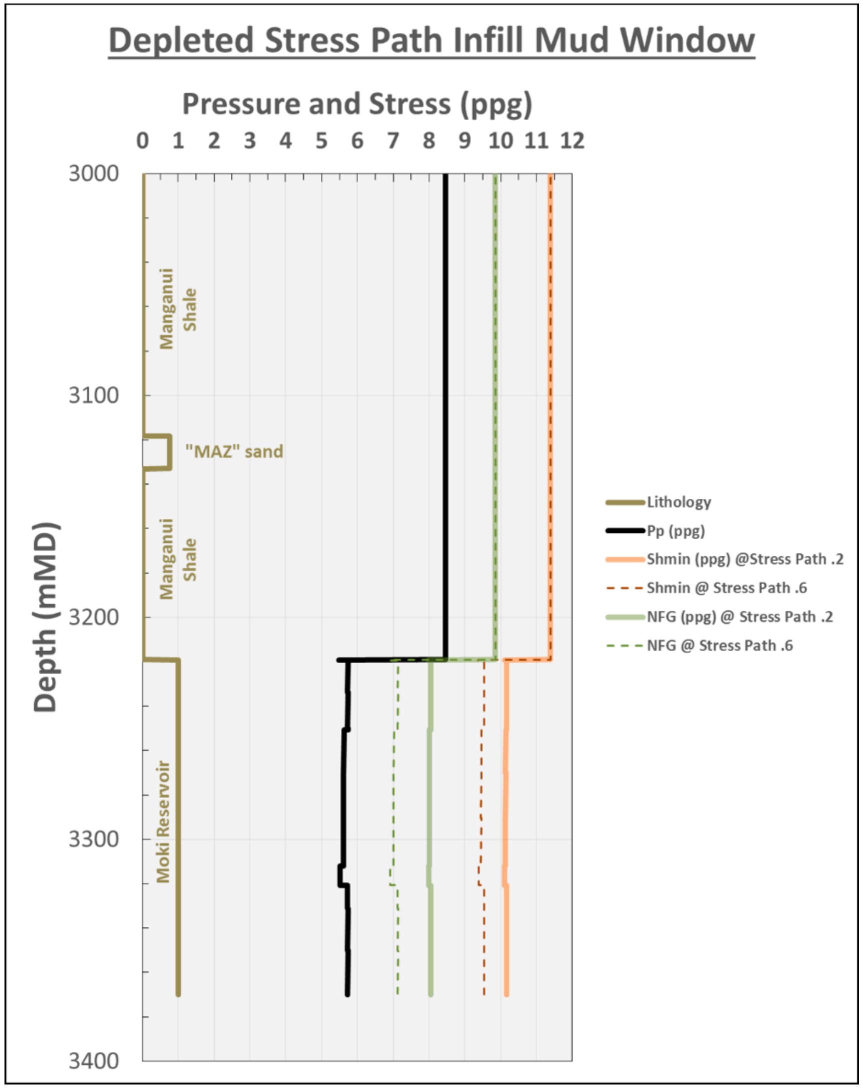


Figure 4. Example of Stress Path mud window prediction for a depleted infill horizontal drilling target. Plot is measured depth vs. ppg units pressure and stress. Brown track approximates lithology, identifying hydrostatic shale overburden, thin hydrostatic sand above reservoir, and pressure-depleted Moki sand reservoir target. Black curve is a predicted pore pressure scenario from Maari dynamic reservoir model. Green curve is calculation of Natural Fracture Gradient (NFG) using SRT-defined stress path = 0.205. Orange track is calculation of Shmin fracture gradient using SRT-defined stress path = 0.205. In the absence of SRT or other calibration of stress path, a reasonable assumption would be 0.6 (dashed line fracture gradients). Knowledge of Stress Path from SRT interpretation calibrates the prediction, providing a more confident result for well planning.

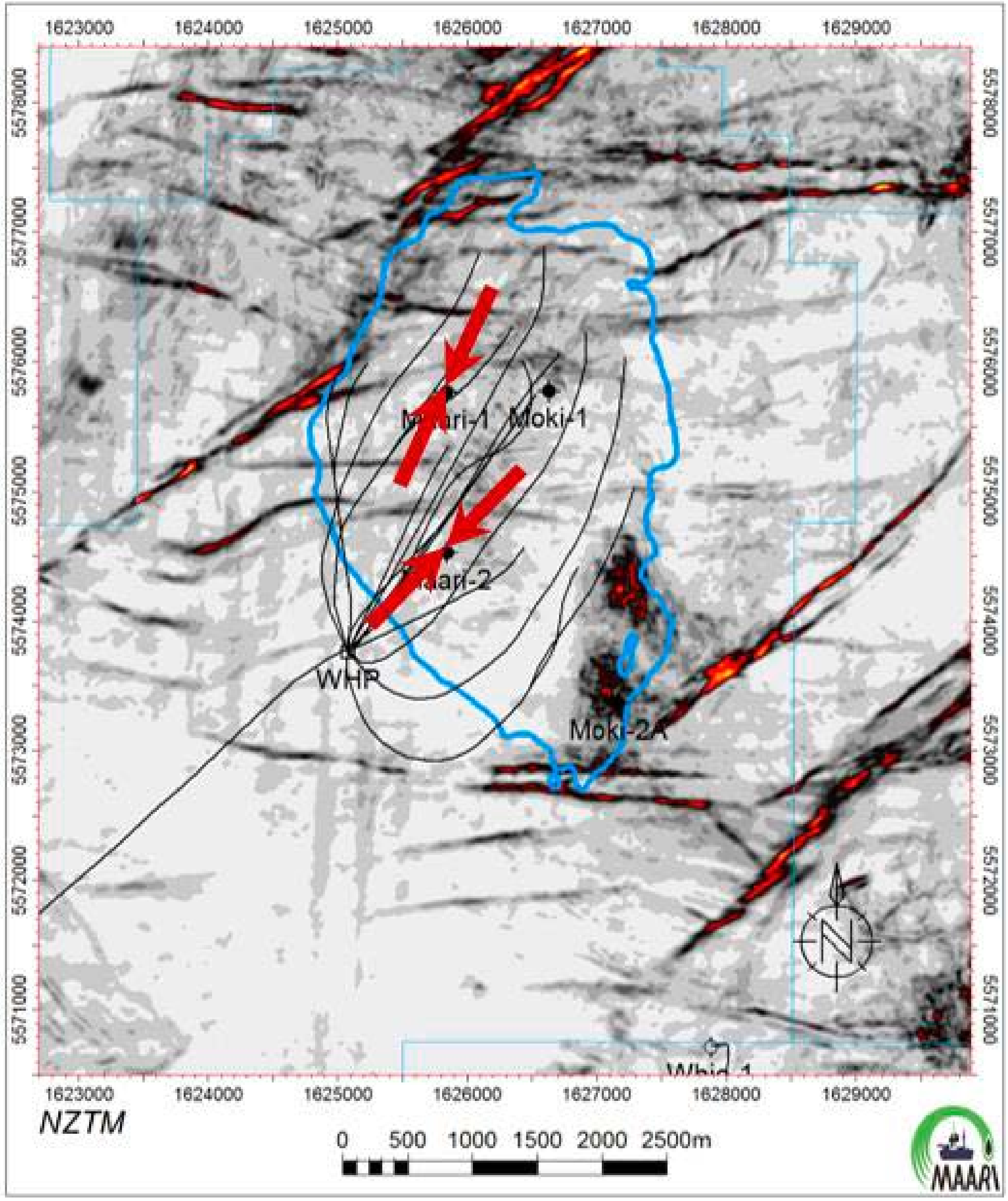


Figure 5. Maari 3D seismic coherence extraction on shallow base Pliocene unconformity as a proxy for recently active faults. Two sets of recently active faults are displayed. SW-NE faults are extensional and possibly responsible for Maari OWC (note correspondence with blue OWC polygon on west side of field). W-E faults are strike slip. SHmax direction is shown (red arrows) for Maari-1 (N25°E) and Maari-2 (N44°E) appraisal wells.

Maari Geomechanical Model (ppg)				
	P_P	S_V	S_{Hmax}	S_{hmin}
Initial	8.65	17.60	17.40	11.40
Depleted	5.51	17.60	16.80	10.12

Table 1. Maari geomechanical model. Initial data from Maari-1 and Maari-2 appraisal wells. Depleted data from MR1 SRTs and Stress Path interpretation (=0.205). Direction of SHmax is N25°E at Maari-1 and N44°E at Maari-2.