PS A Viscoplastic Stress Relaxation Model for Predicting Variations of the Least Principal Stress With Depth in Unconventional Reservoirs*

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Abstract

In this paper we extend the viscoplastic stress relaxation model of Sone and Zoback (Jour. Petrol. Sci. and Eng., 2014) for predicting variations of least principal stress with depth and its impact on the vertical propagation of hydraulic fractures. Viscoplastic stress relaxation makes the stress field in the reservoir more isotropic. In normal faulting and strike-slip faulting environments, this causes the least principal stress to increase. Thus, formations with more viscoplastic stress relaxation are more likely to be frac barriers. In order to predict the magnitude of viscoplastic stress relaxation in different unconventional formations, we generalize the constitutive law developed from a wide range of creep experiments in our lab over the past several years and apply it to an area where stacked pay is being developed by drilling multiple horizontal wells at different depths in the Permian Basin of west Texas. Using frac gradients measured from DFIT (Diagnostic Fracture Injection Test), we empirically calibrate one of the viscoplastic parameters that would ideally be determined by creep experiments and find that it correlates well with the mineral composition. In the formations tested, low QFM (Quartz, Feldspar, and Mica) content tends to correlate with greater viscoplasticity and less anisotropy between the two horizontal principal stresses. The viscoplastic model does a good job of explaining vertical hydraulic fracture propagation, as indicated by the distribution of microseismic events recorded during stimulation.

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INTRODUCTION

Viscoplastic stress relaxation in clay-rich sedimentary rocks leads to a more isotropic state of stress. In normal faulting environments, this causes the least principal stress to increase. Thus, formations that are more viscoplastic are likely to have higher values of the least principal stress (or frac gradient) and are potential barriers to vertical hydraulic fracture propagation. In order to predict the magnitude of viscoplastic stress relaxation in different unconventional formations, we generalize the constitutive law developed from a wide range of creep experiments in our lab over the past several years and apply it to an area where stacked pay is being developed by drilling multiple horizontal wells at different depths in the Permian Basin of west Texas. Using frac gradients measured from DFITs (Diagnostic Fracture Injection Tests) and viscoplastic constitutive parameters measured from core samples, we calculate the relative magnitude of the least principal stress at different depths. In the case study described here, the predicted frac barrier is confirmed by the vertical distribution of microseismic events recorded during stimulation.

STRESS RELAXATION THEORY

The constitutive law developed for viscoplastic stress relaxation is as follows:

$$\sigma(t) = \varepsilon_0 \frac{1}{B(1-n)} t^{-n}$$

where σ(t) is the differential stress with time; B is a measure of the elastic compliance of the rock; n is a dimensionless parameter that describes the tendency to exhibit time-dependent deformation; ε_0 is the total strain. Sone and Zoback (2014) showed that B = 1/E, E is the Young's modulus. Therefore, when applying this constitutive law into the reservoir as,

$$S_V - S_{hmin} = \varepsilon_0 \frac{E}{(1-n)} t^{-n}$$

which only holds for normal faulting regime, since we write the differential stress σ(t) as the vertical stress minus the minimum horizontal principal stress. Figure 1 is a conceptual diagram illustrating how stress relaxation in different layers could affect the magnitude of the least principal stress with depth.

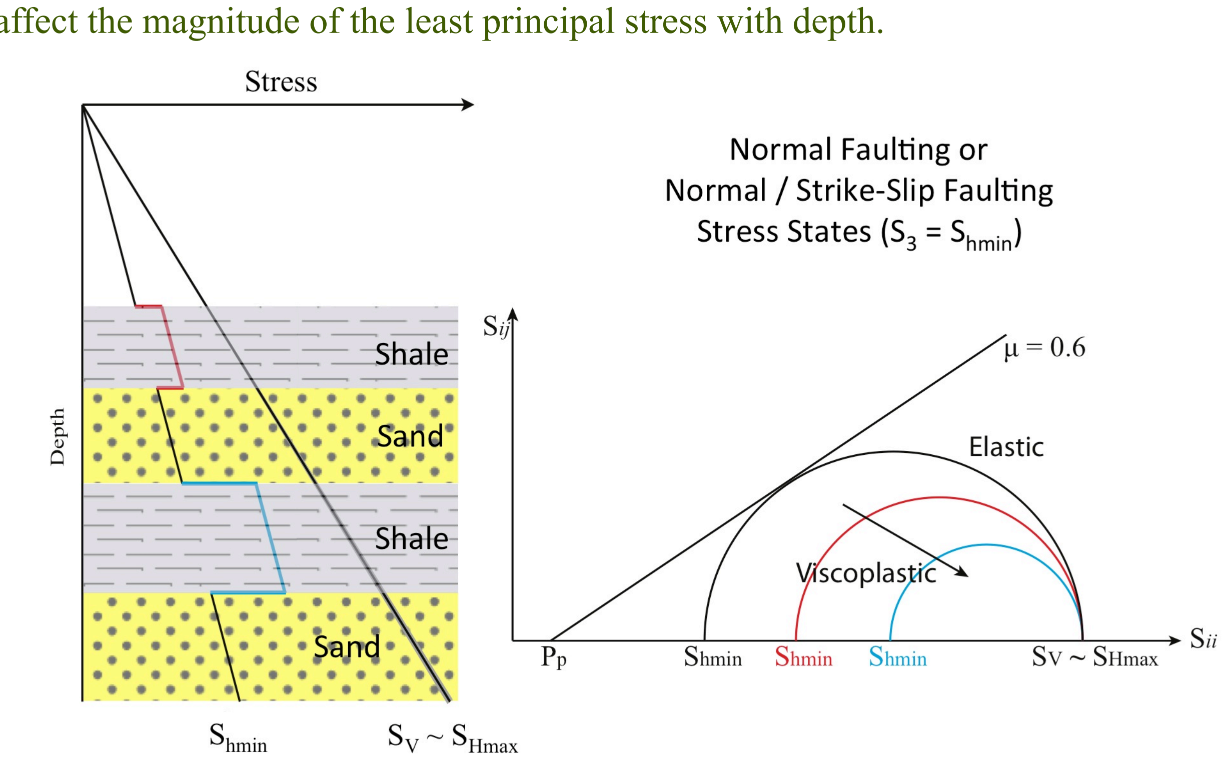

Figure 1: Stress relaxation in stacked elastic and viscoplastic layers and the corresponding Mohr Diagram.

In elastic and brittle formations like sandstone, there is very little stress relaxation, and the corresponding Mohr circle is large; in a viscoplastic shale layer with a relatively small degree of viscoplasticity, there is a small degree of stress relaxation and a moderate increase in S_{hmin} (as shown in red in the schematic cross section and the corresponding Mohr circle); in a more viscoplastic layer (shown in blue) S_{hmin} increases even more.

PERMIAN BASIN CASE STUDY

Figure 2 shows the trajectories of the wells considered in this case study. A, B, C, and D are treatment wells and M is a microseismic monitoring well. In wells A, B, and C, DFIT measurements were made at three different depths. Wells A, B, C, and D were hydraulically fractured to stimulate production; microseismic events were monitored by the geophones in well M during the frac treatment. These observations are used below when we analyze the influence of variations of fracture gradients on vertical hydraulic fracture propagation. Geophysical logs as well as core samples are available in well M; these are used for measuring viscoplastic constitutive parameters B and n in the laboratory.

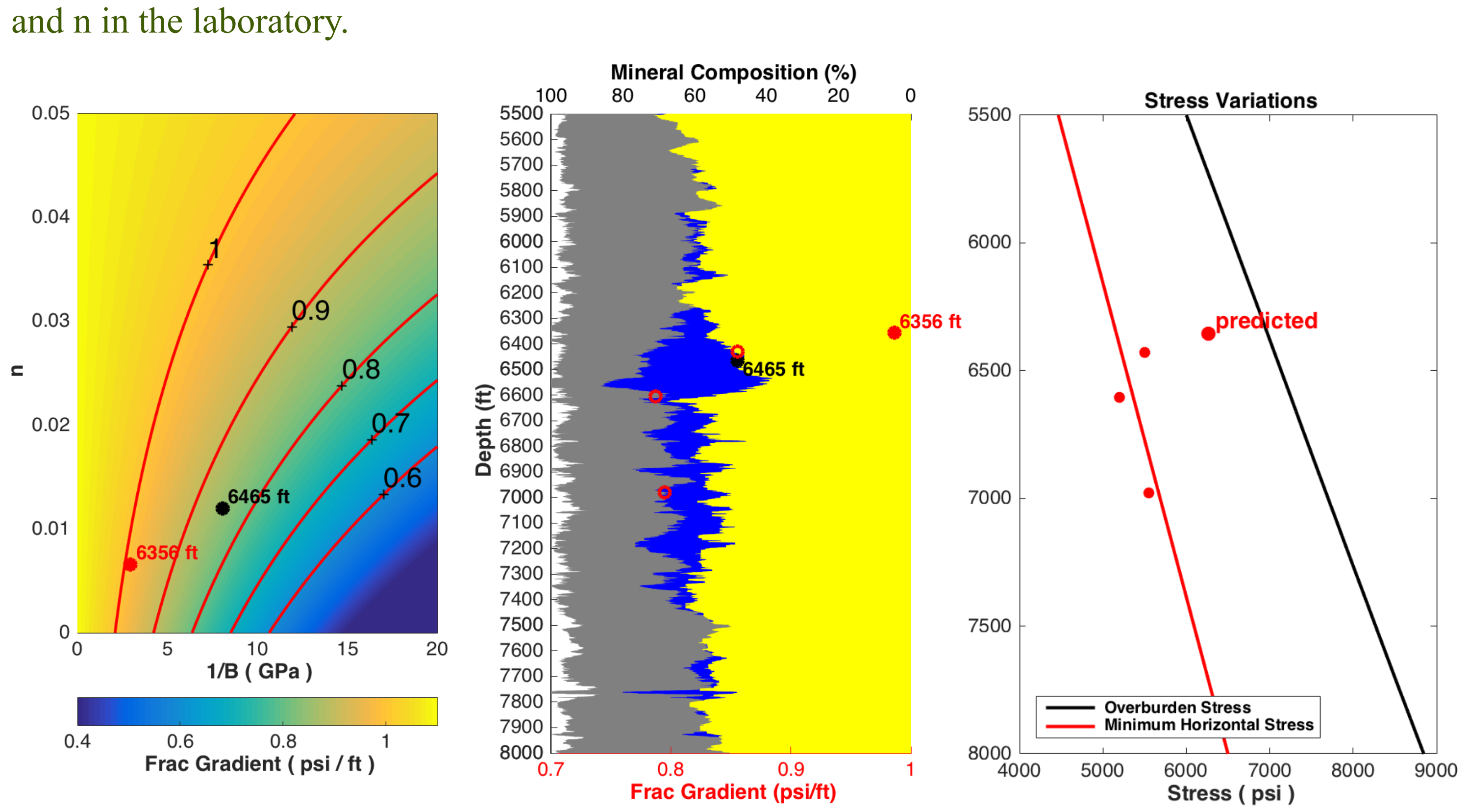

Figure 3: Relation between B, n, and frac gradient (left panel); Frac gradients with depth overlap on the mineral composition: gray-clay, blue-carbonate, yellow-QFM (middle panel); Predicted least principal stress with DFIT measurements (right panel).

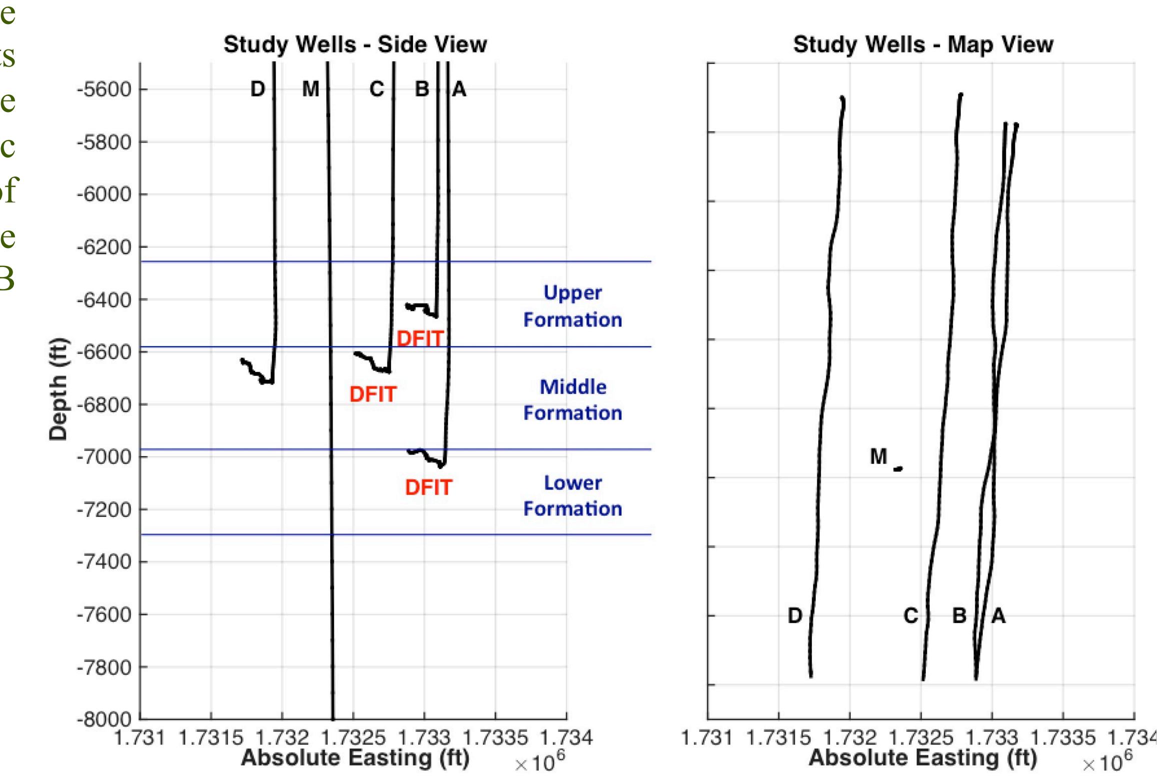

Figure 2: The cross section and the map view of the trajectories of the studied wells. Wells A, B, C, and D are treatment wells, and Well M is a microseismic monitoring well also used for logging and coring.

B and n values are measured for two vertical samples at two different depths, 6356ft and 6465ft, respectively (Rassouli and Zoback, 2016). Three least principal stresses from DFITs are shown by open circles in the middle panel of Figure 3. Fortunately, the depth of one DFIT is very close to 6465ft, where we measure B and n values. Thus, we use measured B, n, and the least principal stress to backward calculate the total strain ε_0, which is about 2×10^{-3}.

Then, applying this total strain to the other depth, 6356ft, we predict the frac gradient to be about 0.98 psi/ft, and plot this frac gradient in the middle panel of Figure 3. Converting this frac gradient into least principal stress, we plot both the measured least principal stresses at different depths and the predicted least principal stress in the right panel of Figure 3. The least principal stress at 6356ft is large compared with three DFITs, indicating there is a frac barrier around this depth.

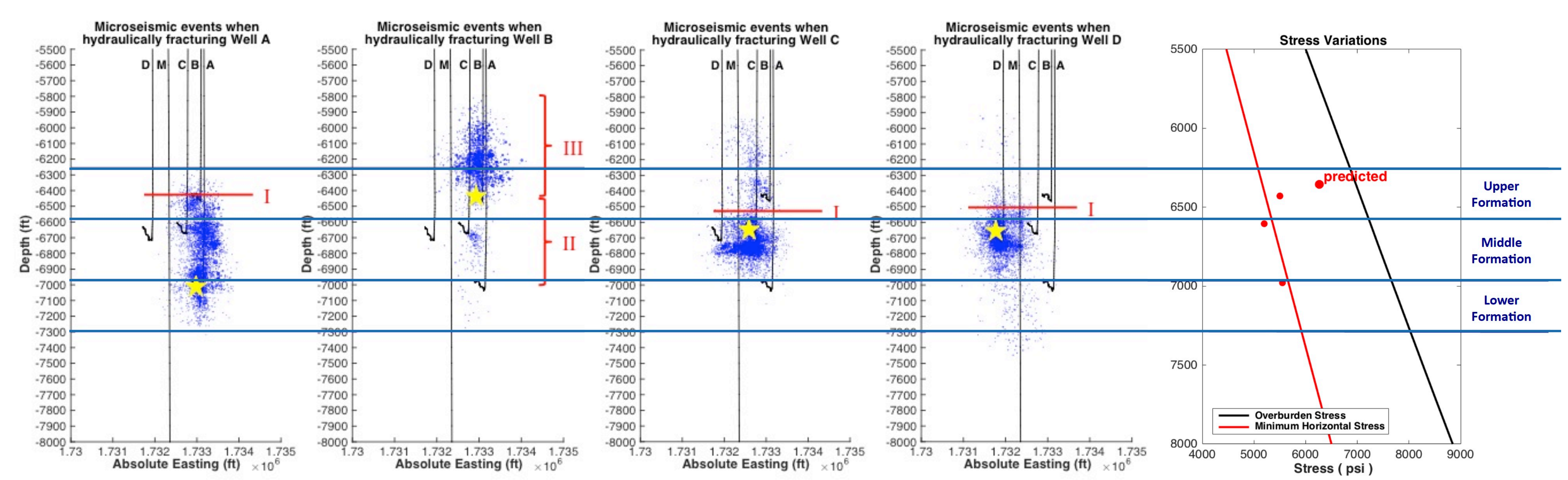

Figure 4: Vertical growth of hydraulic fractures (indicated by microseismic events) controlled by least principal stress variations

This frac barrier is confirmed by microseismic events if we assume that the depths of microseismic events represent the vertical growth of hydraulic fractures. There are two features to note in Figure 4: (1) As seen in the first panel, when well A was hydraulically fractured in the upper part of the lower formation, the upward propagation of hydraulic fractures appears to have been limited by the predicted high least principal stress in the upper formation. The same behavior is seen in the third and fourth panels, when wells C and D were hydraulically fractured in the middle formation. (2) As seen in the second panel, when well B was hydraulically fractured in the middle of upper formation, where the least principal stress is very high, we would expect both upward and downward propagation of hydraulic fractures due to the low least principal stress. However, very few micro-earthquakes are seen below well B, presumably because the micro-earthquakes were already triggered during the fracturing of well A, which is very close (Figure 2).

GENERALIZATION

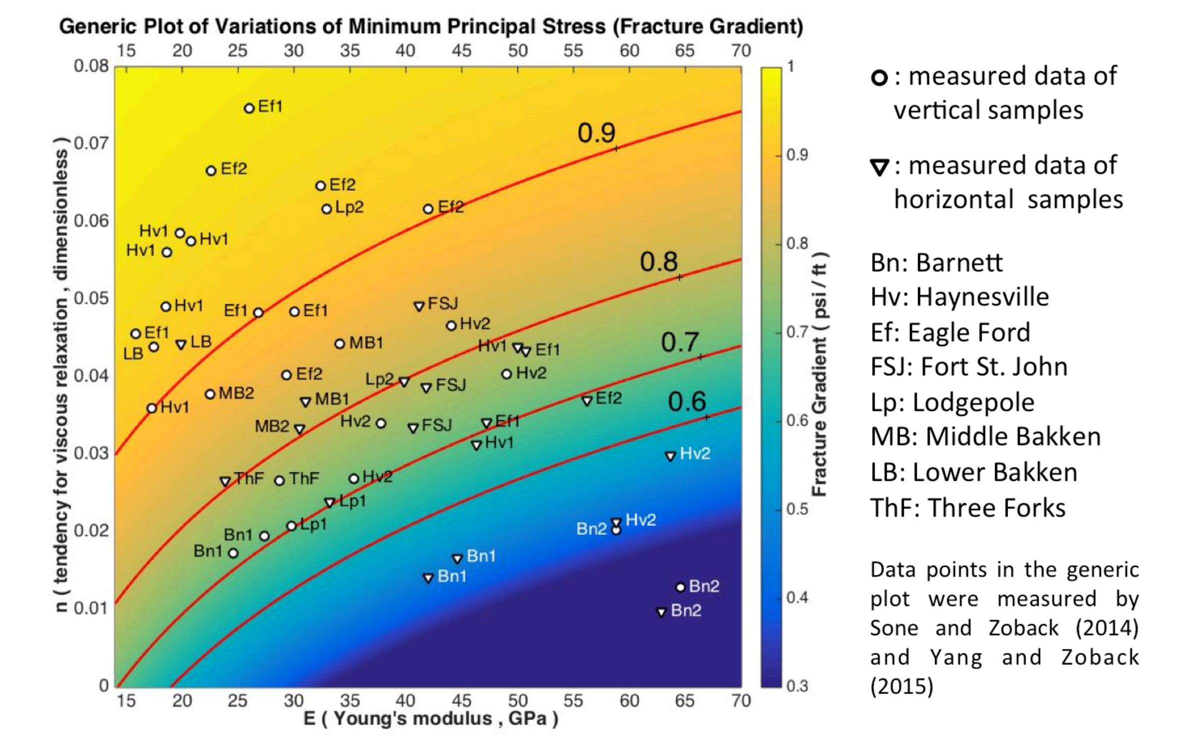

Figure 5: Generic viscoplastic stress relaxation plot overlapped by measured B and n values of different shale formations.

Since most unconventional reservoirs are in a normal faulting or normal/strike-slip faulting environments, by assuming the overburden gradient is about 1 psi/ft, the total strain is about 1×10^{-3}, we can predict the fracture gradient for different formations using a generic viscoplastic stress relaxation plot as in Figure 5 assuming near hydrostatic pore pressure. In Figure 5, each data point is a measured n and B, labeled by the formation name. In the upper left corner of the plot, since n is high and B is low, the formations are more viscoplastic; in the lower right corner of the plot, since n is low and B is high, the formations are more elastic. However, as a result of frictional equilibrium, the fracture gradient cannot be lower than 0.6 psi/ft. This generic viscoplastic stress relaxation model does not consider variations in pore pressures which can be important in some reservoirs.

FUTURE WORK

- Validate the viscoplastic stress relaxation model using core measurements and DFITs from other case studies
- Extend the viscoplastic stress relaxation model to a strike-slip faulting regime which will require development a three-dimensional viscoplastic mode

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