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Viscous relaxation model for predicting least principal stress magnitudes in sedimentary rocks

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ABSTRACT

We propose a new method for estimating stress magnitudes as a function of depth in sedimentary formations based on a laboratory constrained viscous rheology and steady tectonic loading. We apply this method to a well drilled in the Barnett shale in the Fort Worth Basin, Texas. Laboratory experiments show that shale gas reservoir rocks exhibit wide range of viscoplastic behavior mostly dominantly controlled by its composition. Stress relaxation in these formations is described by a simple power-law (in time) rheology. We demonstrate that a reasonable profile of the principal stress magnitudes can be obtained from geophysical logs by utilizing (1) the laboratory power-law constitutive law, (2) an estimate of the horizontal tectonic loading, and (3) the assumption that the ratio of principal stress differences ($[S_2-S_3]/[S_1-S_3]$) is relatively uniform with depth. Profiles of the principal stress magnitudes generated based on our proposed method for a vertical well in the Barnett shale generally agree with the occurrence of drilling-induced tensile fractures in the same well. Also, the predicted decrease in the least principal stress (fracture gradient) in the limestone formation underlying the Barnett shale appears to explain the downward propagation of hydraulic fractures observed in this region. This stress change is not captured by the extended Eaton (instantaneous loading) model even when incorporating formation anisotropy. We believe our approach is more consistent with the time-dependent processes associated with stress accumulation over the course of geological time and thus may provide a new method to predict vertical hydraulic fracture growth in targeted reservoirs.

1. Introduction

Predicting variations of the magnitude of least principal stress within sedimentary basins has significant practical value in the petroleum industry. Newly created hydraulic fractures open when the pressure of the injected fluid exceeds the least principal stress magnitude. Knowledge of stress magnitude variation along a production well therefore helps to identify intervals that will, or will not, act as barriers to optimize fracture containment within desired formations.

Direct measurements of the in-situ least principal stress magnitudes in subsurface reservoir formations rely on mini-frac and leak off tests. While these measurements can be conducted with reasonable accuracy, they only provide measurements of the in-situ stress magnitude at a specific depth and repeated measurements (e.g., above, below and within an interval to be hydraulically fractured) are extremely rare. Therefore, log-based algorithms for predicting stress magnitudes have been proposed which can create a continuous profile of the stress magnitude along a well after calibration against the limited direct measurements from mini-frac and leak off tests.

For over 40 years, the approach proposed by Eaton (1969) has been used and adapted by many researchers. The method assumes that the source of horizontal stress is the gravitational load of the overburden. When the vertical stress, S_v, from the overburden load is applied vertically to a formation with lateral confinement (uniaxial strain), the formation also experiences an increase in horizontal stress, S_h. Based on linearly elasticity, this relation between increase in vertical and horizontal stresses was proposed by Eaton to be

$$S_h = \frac{\nu}{1-\nu}(S_v - P_p) + P_p \tag{1}$$

where P_p is the pore pressure and ν is the Poisson's ratio of an isotropic elastic medium. Therefore, if the pore pressure gradient is known and profiles of S_v and ν are determined from density and sonic logs, a profile of the minimum horizontal stress S_h can be obtained. However, despite the wide-spread use of this relation,

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Eaton (1969) recognized from the outset that it was necessary to use an empirically-determined depth-dependent Poisson's ratio that increases from 0.25 (at ~1000 ft) to 0.5 (at 20,000 ft) to fit available measurements of least principal stress in the Gulf of Mexico.

There are several fundamental shortcomings of the model described in Eq. (1). First, after deposition, the overburden load increases with time and burial as rocks undergo compaction and diagenesis which causes elastic properties to evolve throughout the process. Therefore, the use of present day elastic properties is not appropriate to compute the effects of processes that occur over geological time. Secondly, rock deformation involves plastic and time-dependent components not captured by linear elasticity and the assumption of instantaneously applied stress. Plastic deformation (e.g. compaction, fracturing, or faulting) do not contribute to the overall buildup of elastic stress but releases stress. Reservoir rocks can also exhibit time-dependent deformational behavior which can alter stress states through flow deformation over geological time depending on the degree to which it occurs (Sone and Zoback, 2014). These inelastic time-dependent effects cannot be ignored when considering processes leading up to the present day stress states. Finally, the overburden load is not the only source of horizontal stress, but tectonic processes also contribute to the horizontal stresses. While Eq. (1) predicts S_h less than or equal to S_v, observations of strike-slip earthquakes ($S_{Hmax} > S_v > S_{hmin}$) and reverse faulting earthquakes ($S_{Hmax} > S_{hmin} > S_v$) provide clear evidence of horizontal stresses from sources other than gravitational loading.

To overcome some of these shortcomings, various modifications to Eq. (1) have been proposed in the past (we refer to these as the "extended Eaton models") which also incorporate the effects of elastic anisotropy, poroelasticity, and tectonic loading (e.g. Amadei et al., 1987; Thiercelin and Plumb, 1994). Eq. (2) below is one such equation by Thiercelin and Plumb (1994), which assumes vertical transverse isotropy and horizontal tectonic loading

$$S_{\mathrm{hmin}} - \alpha P_p = \frac{E_h}{E_v}\frac{\nu_v}{1-\nu_h}(S_v - \alpha P_p) + \frac{E_h}{1-\nu_h^2}(\varepsilon_h - \nu_h \varepsilon_H)$$

$$S_{\mathrm{Hmax}} - \alpha P_p = \frac{E_h}{E_v}\frac{\nu_v}{1-\nu_h}(S_v - \alpha P_p) + \frac{E_h}{1-\nu_h^2}(\varepsilon_H - \nu_h \varepsilon_h) \tag{2}$$

here E_v and E_h are the vertical and horizontal Young's moduli, respectively; ν_v and ν_h are the vertical and horizontal Poisson's ratio, respectively; α is the Biot's coefficient; ε_H and ε_h are the tectonic strains in the direction parallel to the maximum and minimum horizontal principal stresses (S_{Hmax} and S_{hmin}). In Eq. (2), the first term is the horizontal stress due to gravitational loading (S_h) similar to Eq. (1) except in the anisotropic form. The second term describes the horizontal stresses arising from horizontal tectonic strains with constant strain boundary condition in the horizontal direction and constant stress boundary condition in the vertical direction.

The addition of the horizontal tectonic loading particularly allows the presence of more compressive environments ($S_h \geq S_v$) which was not realizable in the original equation, and also appeared to explain the bed-to-bed variation in horizontal stress magnitudes observed in some sand-shale sequences in North America (Kry and Gronseth, 1983; Hickman et al., 1985; Evans et al., 1989a). In these studies, in-situ horizontal stress magnitudes measured in boreholes were observed to be lower in the shale/siltstone layers than in the adjacent sandstone units. By comparing field stress data in the Appalachian Plateau with core mechanical properties (Evans et al., 1989b) and geophysical log data (Plumb et al., 1991), it was concluded that variation in horizontal stress correlates with the Young's modulus of the formation better than with the Poisson's ratio. These studies suggested that horizontal stress magnitudes are lower in the compliant shale layers compared to the adjacent stiff sandstones because tectonic horizontal stress caused by a given amount of tectonic strain is proportional to the elastic stiffness.

However, while some local examples of horizontal stress variation may be consistent with these elastic models, other observations are not. For instance in the Paris basin, minimum horizontal stress magnitudes are found to be larger within the clay-rich Bure argillite where the elastic modulus is smaller compared to the adjacent limestone (Gunzburger and Cornet, 2007). Also hydraulic fractures created in the Barnett shale are sometimes observed to extend downwards into the underlying limestone formations (Fisher and Warpinski, 2011) although these limestone formations are stiffer compared to the Barnett shale formation and according to extended Eaton models, they should act as fracture barriers due to the higher stress (see below).

Several studies have also incorporated viscoelastic rheology with detail consideration of the basin history (Prats, 1981; Warpinski, 1989), but these calculations were based on arbitrary viscoelastic constitutive laws not constrained through laboratory experiments but convenient for numerical calculations. Thus models based on more realistic rock behavior justified through laboratory experiments are needed.

In this paper, we propose a new method for estimating stress magnitude variations in shale gas reservoirs. The method superimposes the effect of tectonic loading and viscous stress relaxation, which is based on laboratory-observed creep behavior of a diverse suite of shale gas reservoir rock (Sone and Zoback, 2014). We first examine geophysical log data from a vertical well in Barnett shale, Fort Worth basin, Texas, to obtain information about the in-situ stress variation in shale gas reservoirs. Then laboratory results from creep experiments using core samples from several shale gas reservoirs are discussed to explore the possible relation between viscous formation properties and spatial variation in horizontal stress differences. We then finally attempt to calculate the profile of minimum horizontal principal stress based on the viscous formation properties. Results from our method are compared with those obtained from commonly used extended Eaton models.

2. In-situ stress in a vertical well from Barnett shale, Fort Worth Basin, Texas

2.1. Local geology in the studied well

We studied a set of geophysical and electrical image log that was obtained from a vertical well drilled in the northeastern region (Newark East Field) of the Fort Worth basin, Texas, to study the stress state around the Barnett shale formation and its relation to petrophysical properties. At this location, the Barnett shale is over 1000 ft (300 m) in thickness, divided into two units (upper and lower Barnett) by the Forestburg limestone, and overlies the Viola Limestone Formation (Fig. 1).

We find the upper Barnett shale to be the quartz/clay rich unit that extends from about 7695–7840 ft in this well overlying the Forestburg limestone below. The lower extent of the Forestburg limestone is unclear, but we believe that it extends to about 8000 ft where rapid inter-layering of high- and low-resistivity units starts to appear in the electrical image log. This rapidly inter-layered section which occurs at the top of the lower Barnett shale is referred as the "lime wash" (Pollastro et al., 2007). The mineral compositions in this interval obtained through analysis of elemental capture spectroscopy range from almost completely carbonate-dominated (>90%) rocks, to quartz, feldspar, mica-