Journal of Unconventional Oil and Gas Resources xxx (2015) xxx–xxx

Contents lists available at ScienceDirect

Journal of Unconventional Oil and Gas Resources

journal homepage: www.elsevier.com/locate/juogr

Fracture-permeability behavior of shale

J. William Carey *, Zhou Lei, Esteban Rougier, Hiroko Mori, Hari Viswanathan

Earth and Environmental Sciences Division, Los Alamos National Laboratory, Los Alamos, NM 87545, USA

ARTICLE INFO

Article history:
Received 23 December 2014
Revised 8 April 2015
Accepted 20 April 2015
Available online xxxx

Keywords:
Hydraulic fracturing
Shale gas
Caprock integrity
Geomechanics
CO_2 sequestration

ABSTRACT

The fracture-permeability behavior of Utica shale, an important play for shale gas and oil, was investigated using a triaxial coreflood device and X-ray tomography in combination with finite-discrete element modeling (FDEM). Fractures were generated in both compression and in a direct-shear configuration that allowed permeability to be measured across the faces of cylindrical core. Shale with bedding planes perpendicular to direct-shear loading developed complex fracture networks and peak permeability of 30 mD that fell to 5 mD under hydrostatic conditions. Shale with bedding planes parallel to shear loading developed simple fractures with peak permeability as high as 900 mD. In addition to the large anisotropy in fracture permeability, the amount of deformation required to initiate fractures was greater for perpendicular layering (about 1% versus 0.4%), and in both cases activation of existing fractures are more likely sources of permeability in shale gas plays or damaged caprock in CO_2 sequestration because of the significant deformation required to form new fracture networks. FDEM numerical simulations were able to replicate the main features of the fracturing processes while showing the importance of fluid penetration into fractures as well as layering in determining fracture patterns.

Introduction

Fracture permeability in shale[1] is crucial to understanding production of hydrocarbon during hydraulic fracturing operations and the trapping of buoyant fluids in reservoirs, including CO_2 sequestration projects. However, several studies suggest that the mechanisms that generate permeability and govern fluid flow through fractured shale are poorly understood (e.g., Dewhurst et al., 1999; Nygård et al., 2006; Dusseault and McLennan, 2011; Vincent, 2012; Gomaa et al., 2014). This has consequences including risks that injection-triggered seismicity may allow stored CO_2 to escape through damaged caprock (Zoback and Gorelick, 2012). There are several lines of evidence that suggest that creating long-lasting permeability in shale is difficult. For example, in hydraulic fracturing the use of proppants is apparently required to maintain the permeability of the generated fracture system. Shale and other mudstone are well known for their tendency toward plastic deformation or creep while under stress that may close or seal fractures. Studies by Kohli and Zoback (2013) show a clear connection between clay and organic content of shale and the tendency toward creep. Extensive studies of shale fracture behavior in European nuclear waste storage programs have observed self-sealing of fractured shale in tunnels as well as in experimental studies (e.g., Bastiaens et al., 2007; Davy et al., 2007; Bock et al., 2010). Finally, faults within clay-rich rocks are known to act both as seals and fluid conduits in petroleum reservoirs (fault compartmentalization; e.g., Dewhurst et al., 1999; Fisher and Knipe, 2001).

The study of permeability in damaged shale is challenging for several reasons that include the tendency of these materials toward ductile deformation such that representative permeability values must be obtained at the stress conditions of interest. As pressure and temperature increase, shale behavior transitions from more brittle to more ductile deformation. Shale gas reservoirs or shale geologic barriers may be more likely to fracture or fail by ductile deformation and thus may not form high permeability pathways.

The literature on permeability of fractured shale is limited. Most studies have considered the permeability of artificial fractures (sawn or split samples) or artificially separated natural fractures using triaxial or shear-box devices (e.g., Gutierrez et al., 2000; Davy et al., 2007; Bernier et al., 2007; Zhang, 2013; Zhang et al., 2013; Cho et al., 2013). These provide valuable data on fracture behavior but are not able to address questions concerning the permeability and behavior of natural, stress-induced fractures. Very few studies have been conducted under *in situ* conditions with simultaneous fracture and permeability measurements at reservoir condition. Nygård et al. (2006) examined a single shale sample and found an increase in flow rate of about a factor of 10 in a triaxial

* Corresponding author. Tel.: +1 (505) 667 5540.
E-mail address: bcarey@lanl.gov (J.W. Carey).

[1] In this usage, shale refers to clay-rich sedimentary rocks.

http://dx.doi.org/10.1016/j.juogr.2015.04.003
2213-3976/© 2015 Published by Elsevier Ltd.

compression study, concluding that it was possible to generate permeability in shale with laboratory methods. There are several *in situ* fracture-permeability studies of shale in relation to the security of nuclear waste storage. Bernier et al. (2007) conducted hydraulic fracture tests on hollow samples within a triaxial device. They observed 4–5 order of magnitude increases in permeability from initial values between 10^{-22} and 10^{-19} m^2, but also found that self-sealing processes reduced initial permeability. Zhang and Rothfuchs (2008) conducted triaxial compression studies and generated fractures in shale at about 30° from the axial load and observed an increase in permeability from 10^{-22} to 10^{-18} m^2. They also observed that with time and application of hydrostatic or deviatoric stress the permeability decreased, in some cases returning to pre-fracture values.

There is an extensive literature on brittle and ductile behavior in shale and the various factors that may be used to predict the possible mechanical behavior of shale in response to stress (e.g., Ingram and Urai, 1999). However, as this brief introduction suggests, much less is known about the relationship between these mechanical properties and the permeability of damaged shale. In order to understand what limits the production of hydrocarbon in hydraulic fracturing, we must have basic knowledge of fracture-permeability relations. Similarly, if we are to assess risk to CO_2 storage integrity, we must understand the capacity of faulted shale systems to flow multiphase fluids. In this study, we examine the behavior of shear fractures. While tensile fractures are characteristic of how the hydraulic fracturing process accommodates proppants and fluid, microseismicity demonstrates shear fracture formation or activation (Warpinski et al., 2004; Rutledge et al., 2004; Maxwell, 2010). Additional research suggests that the primary source of hydrocarbon in hydraulic fracturing is through activation of pre-existing shear fractures rather than the creation of new fracture permeability (Johri and Zoback, 2013; McClure and Horne, 2014). In any case, whether a shear fracture is newly created or pre-existing, characterization of the fracture permeability is essential to understanding hydrocarbon production and potential leakage processes.

We address these issues using a combination of experimental and computational methods to study fracture generation and permeability of shale at *in situ* shallow reservoir conditions. The experiments utilize a triaxial coreflood device in combination with X-ray computed tomography (XCT). In addition to conventional compression experiments, we introduce a direct-shear technique using the triaxial device to generate hydraulically conductive fractures in shale. We examine the material deformation and permeability in relation to shale anisotropy (i.e., bedding), confining pressure and pore pressure from both water and supercritical CO_2. We conduct computational modeling with the combined finite-discrete element method (FDEM; Munjiza, 2004; Munjiza et al., 2012) to investigate initial stress conditions and to reproduce deformation and failure patterns in shale.

The primary objectives of this study are to develop a new experimental approach to the study of fracture-permeability in shale at reservoir conditions. In this work, we focus on low temperature and low confining pressure conditions to maximize brittle behavior. The intent of the experiments is not to generate quantitative measurements of mechanical properties, but to explore the character and permeability of fracture networks and to provide estimates of the potential magnitude of permeability in fracture-damaged shale. We conduct investigations with both water and supercritical CO_2 as part of research on the use of supercritical CO_2 as an alternative fracturing fluid as well as studies of caprock integrity in CO_2 storage. The main drivers for the numerical analysis are to illustrate and to gain more insight on the stress distribution within the sample during the direct shear experiments; to investigate the impact of the fluid pressure inside the fracture on the development of fractures and final fracture pattern; and to examine the role of bonding strength between the bedding planes on the resulting fracture patterns.

Experimental methods

The experiments were conducted in a triaxial coreflood system coupled with an X-ray tomography unit. The triaxial coreflood system was designed to simultaneously measure permeability of rocks under increasing stress up to and beyond mechanical failure including the *in situ* formation of fluid-transmissive fractures (Fig. 1). The system has independent control of the confining pressure (max 34.5 MPa), the axial pressure (max. 82. MPa), and injection pressure (max. 34.5 MPa) and operates at temperatures ⩽100 °C. Fluids can be injected as either one or two comingled phases using any combination of brine, supercritical CO_2, inert gas, and oil. The system is instrumented with high-precision pressure transducers, linear variable differential transducers for measuring piston displacement, axial and radial strain gages attached directly to the sample, and thermocouples. It also includes acoustic transducers for characterization of acoustic properties of samples as a function of mechanical deformation and fluid saturation. An integrated National Instruments system provides all data acquisition. The triaxial apparatus works with 2.5 cm-diameter core with lengths from 2.5 to 6.5 cm. The X-ray tomography was conducted with a Hamamatsu 150 kV micro-focus X-ray source. The detector is a flat-panel detector with DRZ + scintillation screen. In our configuration the system generates routine resolution at 25 μm (as used in this study) and with long scans can reach 10 μm. Mechanical failure can be investigated in several configurations including traditional compression and direct-shear methods.

In these experiments, the objective was to measure permeability of *in situ* fractured samples. This requires fracture connectivity between the upper and lower triaxial pistons (Fig. 3 below). In order to facilitate this, the pistons, which are constructed of titanium alloy (Ti–6Al–4V), had faces with a machined spoke and wheel pattern to distribute fluid across the face of the core. While typical triaxial experiments utilize a 2:1 length:diameter ratio, we conducted most of these experiments at 1:1 in an attempt to allow intersection of the fractures with the piston faces. While this geometry is not appropriate for accurate measurement of mechanical properties (due to end-effects), this design is useful for our focus on fracture-permeability relations.

A linear variable differential transducer (LVDT) was used to measure piston displacement and total sample compression. The axial deformation was calibrated by comparing the behavior of stainless steel with the shale samples. In addition, we used axial and radial strain transducers that were directly epoxied to the sample midpoint. However, the use of a 1:1 sample geometry meant that the strain data were only qualitatively useful and were not used in the following analysis.

In this study, we focus on shallow reservoir conditions that facilitate brittle behavior. Experiments were conducted at two conditions: 25 °C and 3.45 MPa confining pressure, and 45 °C and 11.7 MPa confining pressure. Permeability at the lower conditions was measured with water; permeability at the higher conditions was measured with water and/or supercritical CO_2. During assembly, the samples were jacketed in shrink-wrap Teflon or a sandwich of Teflon—copper foil—Teflon for use in the supercritical CO_2 experiments. Early experiments showed strong coupling between the pistons and shale samples (extrusion of shale into the grooved-face of the pistons; cone-shaped fractures). This was alleviated by placing a 1-mm porous stainless steel disk (0.5 μm pores; 0.125 D permeability; 65 GPa Young's Modulus; Mott Corporation) between the piston and sample.