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Direct Measurement of Permeability and its Evolution with Stress

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Abstract

Permeability, a key reservoir quality indicator, is pivotal for modelling and forecasting the dynamic behavior of reservoirs. It is also a key input parameter for fracturing simulators. Permeability in shale reservoirs and its variation with stress is complex, as fluid flow occurs both via fractures and ultra-tight pores hosted either by organic matter or inorganic matrix. For tight and ultra-tight rocks, measurements are time intensive and due to a lack of standardized testing protocol, petrophysicists rely on estimating permeability by inverting data obtained from other sources. However, such inversion involves using empirical constants which may not work due to heterogeneity resulting from variation in rock fabric, constituents and pore structure. Reservoir engineers combine analogue production and other empirical data to establish a range of assumed matrix and fracture permeability values, often limiting its forecasting power due to a lack of integration with the geological model and understanding of property controls. The assumed possible model scenarios have a direct impact in the field economics, leading to uncertainty ranges that may prevent projects from meeting the economics screening criteria. The high value of information carried by a baseline matrix permeability measurement and the corresponding fracture uplift in unconventional reservoirs result in a strong business case for direct permeability measurements at representative reservoir conditions and stresses.

This paper reports the results of a multi-well testing campaign designed to measure permeability and its variation with stress for various lithofacies. Using petrophysical modeling and extensive thin section study, dominant lithofacies were first identified in the region of interest. Permeability measurements were undertaken for a large number of samples, selected to adequately represent each lithofacies. Measurements were performed on intact plugs using steady-state and unsteady-state technique. Supercritical nitrogen used as pore fluid offers the benefits of being inert and with viscosity significantly lower than brine and other organic solvents, while eliminating the need for Klinkenberg and Forchheimer corrections. CT scans and thin section images acquired on the tested samples permitted integrating the experimental observations with the observed rock fabric and pore structure.

For the six dominant lithofacies, measured permeability at insitu effective stress varied between 10 nano-Darcy to 32 micro-Darcy. To obtain the permeability of the rock matrix, low resolution plug CT scans were used to screen the samples for any observable fractures. Moreover, permeability hysteresis (permanent damage in permeability, after increasing the effective stress by few thousand psi to mimic drawdown, and then returning to the initial reservoir effective stress) ranged between 4% to 90% and increased with increasing clay content and with decreasing stiffer constituent content. Furthermore, analysis of unsteady-state pressure data for a sample exhibited distinctly different rates of pressure decay, suggesting existence of two separate flow paths which was verified by thin section imaging and micro-CT image analysis. Finally, unsteady-state measurement provided direct measurement of pore volume under stress.

The results of this study can be used to design drawdown/production strategy for field operation. Understanding of permeability hysteresis will help in candidate selection for EOR or re-stimulation operations once a well has been produced for few months and ultimately begun to decline.

Introduction

Hydrocarbon production from shale reservoirs encountered a dramatic increase over past decades with the advent of horizontal drilling technology and multistage hydraulic fracturing. Producing hydrocarbons from these ultra-tight reservoirs are accompanied by additional challenges such as severe production declines (up to 90%) within the first two years of the life of a well (Baihly et al., 2015). Additionally, the expected ultimate recovery is observed to drop to the amount of 10–20% (Baihly et al., 2015) once the near-fracture region is depleted and production rate is entirely dependent on matrix permeability (Chhatre et al., 2015). Changes in permeability through time with continued depletion is thus a key parameter for building a reservoir model, history matching and estimating production (Clarkson, 2013). It is also a key input parameter for fracturing simulators.

Due to a lack of calibrated matrix and fracture permeability measurements in unconventional reservoirs, reservoir engineers combine analogue production and other empirical data to establish a range of assumed matrix and fracture permeability values. Such an approach often limits their forecasting capability since it is not tied back to the geologic model and do not honor the role of rock fabric and microstructure. Since the assumed possible model scenarios have a direct impact in the field economics, this may lead to wide ranges of uncertainty, which in turn may prevent projects from meeting the economic screening criteria. The baseline matrix permeability measurement and the corresponding fracture uplift in unconventional reservoirs provide extremely valuable information and a strong business case for direct permeability measurements at representative reservoir conditions and stresses.

Permeability in shale reservoirs and its variation with stress is complex, as fluid flow occurs both via fractures and ultra-tight pores hosted either by organic matter or inorganic matrix (Rosen et al., 2014; Chhatre et al., 2015; Rydzy et al., 2016). As in the case of any other petrophysical property, rock texture and composition have a first order control over permeability, which are in turn impacted by depositional and diagenetic processes (Rosen et al., 2014). Crushed rock permeability measurement proposed by Luffel et al. (1993) enjoys immense popularity as a suitable technique. However, it was observed that this technique produced variable results among different measurement laboratories, suggesting a clear need for standardization of permeability measurement techniques (Spears et al., 2011). Additionally, crushed rock measurements are usually conducted under unstressed conditions and thus do not represent the flow behavior at in situ reservoir stress conditions (Chahtre et al., 2015). Moreover, the technique inherently involves a large uncertainty (Heller et al., 2014) and possible inclusion of gas slippage effect due to the measurement being carried out at low pressure (Bhandari et al., 2015). Finally, crushing the rock destroys the texture and pore structure that govern the flow paths and do not accurately represent the flow behavior in situ (Rosen et al., 2014). Permeability measurements on intact plugs avoid the shortcomings mentioned above.