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Geomechanical Controls on Matrix/Fracture Permeability of Tight Oil and Liquid-Rich Gas Reservoirs: Implications for Hydraulic Fracturing

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Abstract

In this work, we present results from an ongoing laboratory study investigating the fluid flow characteristics and geomechanics of the Montney and Bakken formations in western Canada. The main objectives are to 1) investigate the geomechanical controls on matrix and fracture permeability of tight oil and liquid-rich gas reservoirs, and, 2) examine the interrelationship between geomechanical properties and fluid flow characteristics of these fine-grained tight rocks. The experimental techniques include Rock-Eval pyrolysis (T_{max}, TOC), bitumen reflectance, grain size analysis, bulk/grain density (porosity), low-pressure gas (N_2) adsorption (surface area, pore size distribution); pressure-decay profile, pulse-decay and crushed-rock gas (N_2, He) permeability; fracture permeability and mechanical hardness tests (Equotip® Piccolo).

Applying multiple analysis techniques on a diverse sample suite (13 core plugs and accompanying cuttings) and extending the work of a previous study (Ghanizadeh et al., 2014), this contribution provides a workflow to fully characterize matrix/fracture permeability and geomechanical properties of fine-grained tight oil/gas reservoirs. For Montney and Bakken formations as examples, we demonstrate that the characterizing geomechanical techniques are rapid and cost-effective and helpful for planning/optimizing of hydraulic stimulation treatment. We present useful correlations between petrophysical and geomechanical properties of tight oil/gas reservoirs.

1. Introduction

The development of tight oil and liquid-rich tight gas reservoirs is currently the primary focus of industry in western Canada due to low natural gas prices in North America. The Montney and Bakken formations in the Western Canadian Sedimentary Basin contain large resources of tight oil, gas and liquid-rich gas, and have recently received a lot of attention from industry (Rivard et al., 2014). Currently, more than 60% of the total wells being drilled in western Canada are targeting the Montney Formation, particularly within its liquid-rich regions (Rivard et al., 2014). Despite large hydrocarbon-in-place resource estimations, these complex heterogeneous reservoirs require innovative exploration and completion strategies to produce oil/gas economically. Due to their low porosity and permeability (within nano- and microdarcy range), economic oil/gas flow rates in these reservoirs can only be achieved by completion technologies such as multi-fractured horizontal wells

(MFHW). The capability to optimize recovery in these reservoirs is still, however, hampered by poor understanding of the fluid transport characteristics in the matrix and fracture systems of these rocks.

It is suggested that secondary fractures, which may consist of natural fractures that were once healed but reactivated during the hydraulic fracturing process, may create substantial pathways for fluid flow from the matrix to propped hydraulic fractures (Cho et al., 2012). Unlike matrix permeability, unpropped/propped (induced) fracture permeability is not routinely measured in the laboratory, but could be of significant importance for production evaluation and forecasting. Steady-state measurements performed on core plugs with artificially-induced fractures are used to estimate fracture permeability in the current study.

Combined with the “in-situ” stress regimes, the geomechanical properties of unconventional oil/gas reservoirs play a key role in drilling, completion and hydraulic fracturing. Standard laboratory techniques for the determination of unconfined compressive strength (UCS), one important geomechanical property, are destructive, time-consuming and expensive. Therefore, indirect mechanical tests have been alternatively used to provide an indication of rock mechanical strength (Verwaal and Mulder 1993; Viles et al. 2011; Solano et al. 2012). A fast, non-destructive technique (Equotip Piccolo hardness test) has been used in the current study to quantify the mechanical properties of these tight rocks. The application of this technique for mechanical characterization of sedimentary rocks has been previously examined (Viles et al. 2011; Solano et al. 2012). However, the possible linkage between the mechanical values obtained by this method and UCS, which has significant implications for reservoir characterization, has been only suggested recently and is still under investigation (Ghanizadeh et al., 2014).

In this work we present results from an ongoing laboratory study investigating the fluid flow characteristics and geomechanics of the Montney and Bakken formations in western Canada. The main objectives are to 1) investigate the geomechanical controls on matrix and fracture permeability of tight oil and liquid-rich gas reservoirs, and, 2) examine the interrelationship between geomechanical properties and fluid flow characteristics of these fine-grained tight rocks.

2. Samples and Experimental Techniques

A total of 13 core plugs (in “as-received” condition) were analyzed in this study. These core plugs were selected from organic-rich (average TOC content > 1%) Montney Formation (eastern British Columbia; 6 core plugs) and Bakken Formation (southern Saskatchewan; 7 core plugs), differing in TOC content, mineralogy (calcite, clay, quartz) and pore network characteristics (porosity, pore size distribution). The experimental techniques include Rock-Eval pyrolysis (T_{max}, TOC), bitumen reflectance, grain size analysis, bulk/grain density (porosity), low-pressure gas (N_2) adsorption (surface area, pore size distribution); pressure-decay profile, pulse-decay and crushed-rock gas (N_2, He) permeability; fracture permeability and mechanical hardness tests (Equotip® Piccolo).

The obtained results are compared to those collected recently (Ghanizadeh et al., 2014) for a sample suite from organic-lean (average TOC content < 1%) Montney Formation (western Alberta, Canada). The application of previously derived correlations between mechanical hardness, permeability and unconfined compressive strength (UCS), as provided by Ghanizadeh et al. (2014), was further examined for the analyzed samples. Details of analysis methods are provided in that study.

3. Selected Results and Discussion

Some selected results from this study are presented in Figures 1-2. The results of bulk permeability measurements performed on a fractured (unpropped) core plug from Montney Formation are shown in Figure 1. The measured bulk permeability values range from 4 to 8 mD, depending on (mean) pore and confining pressures. Interestingly, the effect of mean pore pressure on measured bulk permeability values is as significant as the impact of confining pressure. At a given confining pressure, bulk permeability values decrease up to 25% with increasing mean pore pressure (130-270 kPa). At a given mean pore pressure, however, bulk permeability values decrease up to 20% with increasing confining pressure (5-25 MPa).

Production of tight oil, gas and liquid-rich gas reservoirs depend strongly on the presence and connectivity/conductivity of the stimulated reservoir volume. Even though cementing minerals and surface roughness provide some degree of resistance to fracture closure, the generated/retained natural-fractures are usually relatively unpropped compared to hydraulic fractures. Similar to the rock matrix and hydraulic fractures, the fluid conductivity (permeability) of natural-fractures is dependent on stress. Therefore, incorporating the stress-dependence of natural-fractures (unpropped) is an important step for more realistic evaluation of production performance of these reservoirs. Quantification of unpropped fracture permeability is particularly essential in modeling wells with complex fracture geometry, where fracture stimulation reactivates healed natural fractures. Fracture permeability values measured in this study at various effective stress conditions are compared to that of other productive tight oil/gas plays (Bakken). Based on our observations, fracture (unpropped) permeability in the studied Montney area can be significantly (up to more than eight orders of magnitude) higher than matrix permeability under similar effective stress conditions.

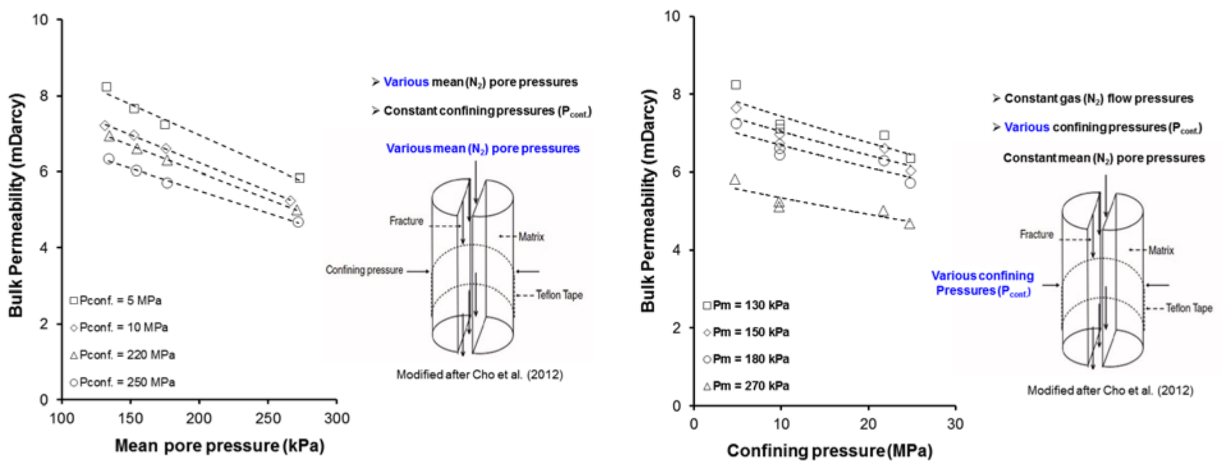

Figure 1: Bulk permeability values measured on a fractured plug from the Montney Formation. The tests were conducted over a range of mean pore pressures (left) and confining pressures (right). Theoretically, the bulk permeability can be approximated as the summation of matrix permeability with the multiplication of fracture porosity and fracture permeability.

For the analyzed formations (Montney, Bakken), the established relationships between mechanical hardness, profile permeability and unconfined compressive strength (UCS) are shown in Figure 2. The data collected by Solano et al. (2012) for the Cardium Formation (Alberta, Canada) are also added to this database. For the analyzed formations, permeability and UCS are related in a gross sense to hardness; permeability decreases with increasing hardness while UCS increases with increasing hardness. The validation of these relationships for other unconventional reservoirs is still under investigation.

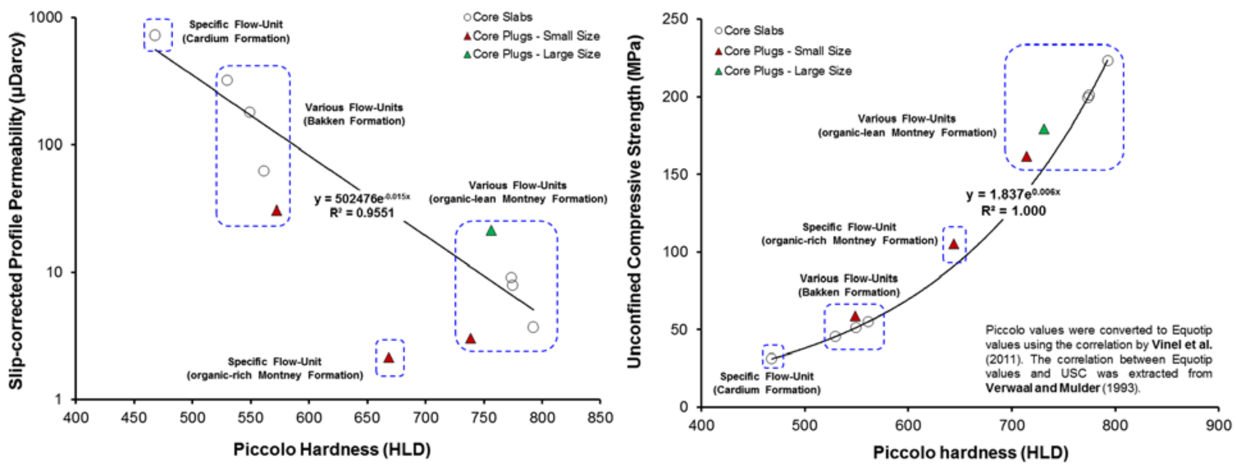

Figure 2: The interrelationship between mechanical hardness and profile permeability values. Different "flow-units" from different Canadian tight oil/gas formations were used to establish this correlation (left). The circle symbols denote the data collected in a previous study (Ghanizadeh et al., 2014) for core slabs. The triangular symbols denote the data collected in this study for core plugs (1.5 inch diameter; 3.8 cm). The length of the core plugs were either 2 (small size) or 3 (large size) inches (5 cm and 7.6 cm, respectively); The interrelationship between mechanical hardness and unconfined compressive Strength (UCS) for different Canadian tight oil/gas reservoirs (right). The procedure for derivation of this correlation is briefly explained within the figure.

The observed interrelationships between mechanical hardness, profile permeability and UCS can be of significant importance for geomechanical characterization of tight oil, gas and liquid-rich gas reservoirs. These correlations can be used to roughly predict profile permeability and mechanical stratigraphy along the drilled core by performing simple, inexpensive, fast "in-situ" hardness tests. The Montney Formation in Alberta and British Columbia is currently undergoing intense development utilizing multi-stage fracturing of horizontal wells. The routine industry practice is to drill single lateral horizontal wells and stimulate them with multi-stage hydraulic fracture treatments. The stimulation treatment has the most dominant impact on the well productivity and it is further the most expensive step of well development. Nevertheless, there are still major uncertainties in determining an optimal development strategy for each interval/area within the Montney Formation. The interrelationships between mechanical hardness, profile permeability and UCS, presented in this study can be treated as an alternative tool to provide rough estimates for at least the preliminary stage of planning of stimulation treatment.

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