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Characterization of fine-scale rock structure and differences in mechanical properties in tight oil reservoirs: An evaluation at the scale of elementary lithological components combining photographic and X-ray computed tomographic imaging, profile-permeability and microhardness testing

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A B S T R A C T

Optimal development of tight-oil resources requires better petrophysical understanding of several key reservoir and mechanical properties. We highlight these for the Cardium Formation at the Pembina field, where controls on these properties appear to occur within *elementary lithological components* (ELCs) at the cm- to sub-cm scale moderated in part by the effects of synsedimentary bioturbation. This complexity in reservoir behavior necessitates new and innovative approaches for petrophysical property estimation, which is the subject of the current work. The workflow outlined starts with the quantification of the volumetric distribution of ELCs. For this purpose, 360° photographic imaging was used to first identify ELCs, and then quantify their volumetric percentages in whole core. This initial step is limited to the exposed surfaces of the core, consequently we used X-ray computed tomography (XRCT) in order to project the ELCs volumetric distribution into the core interior. The correlation between CT number, mineralogy, and bulk density of the rock further allowed porosity to be calculated from XRCT and shed light on its distribution throughout the core interior. Variations in fine-scale permeability were evaluated by collecting pressure-decay profile permeability measurements across a core slab surface following a 5 × 5 mm-2D grid. Relationships between ELCs permeability and porosity were then generated and, when combined with the volumetric distribution of ELCs previously assessed, enabled a 3D distribution of reservoir quality at the mm-scale throughout the core. Finally, microhardness data was collected on the same 2D grid enabling ELC-scale quantification of mechanical properties. Reservoir properties of whole core samples identified in previous publications appear to be reasonably predicted when utilizing ELCs-specific permeability versus porosity transforms and volumetric percentages generated in this study, thus demonstrating scale-up potential.

Introduction

Unconventional, low-permeability (tight) clastic reservoirs are known to contain fine-scale heterogeneities that affect flow of hydrocarbons. For example recent studies (Clarkson et al., 2012; Ghanizadeh et al., 2015a) have demonstrated that permeability measured with a pressure-decay profile permeameter (PDPK) at an interval of 2.54 cm along vertical profiles of tight Montney and Bakken Formations cores can vary by several fold within one metre. Both Montney and Bakken Formations intervals targeted in those investigations contain fine-scale (mm) laminations with variations in grain sizes that affect both horizontal (parallel to bedding) and vertical (perpendicular to bedding) permeability. The high resolution of permeability measurements used in those studies aided greatly with the assessment of flow units (Ghanizadeh et al., 2015b), and assisted with the targeting of horizontal laterals drilled to exploit additional hydrocarbon resources. Further, when enhanced oil recovery operations are considered, such as for the Bakken Formation, sweep efficiency of waterflood and gas injection operations could be better predicted when high resolution permeability measurements are used in reservoir models.

Ghanizadeh et al. (2015b), stimulated by work performed by Solano et al. (2012), demonstrated that mechanical hardness

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measurements could be performed at the same location as PDPK measurements in vertical cores, and that they may be used to estimate fine-scale variations in mechanical properties (such as unconfined compressive strength). Ghanizadeh et al. (2015b) inferred further that mechanical properties in the vertical cores studied are largely affected by the degree of cementation of the samples and concluded that these variations in mechanical properties may be used in the design of drilling and completion programs. For example, in the case of samples from the middle Bakken Formation (Ghanizadeh et al., 2015b), the interval is relatively thin (<10 m) and overlain by a shale, which in turn is overlain by an aquifer. The detailed mechanical property estimates obtained in that study could therefore be used to populate frac models for better prediction of fracture height growth, and mitigation of fracturing into the overlaying aquifer.

The study which we present is also an investigation of fine-scale variations in reservoir and mechanical properties in an unconventional (tight oil) reservoir, but with several differences from Ghanizadeh et al. (2015b). First, fine-scale differences in vertical and horizontal lithological properties observed to occur in the Pembina Cardium reservoir are due partly to the effects of bioturbation as noted earlier by Solano et al. (2012). However, in this paper we make estimates of their 3D volumetric variations in lithology and their associated reservoir properties. Second, using X-ray computed tomography (XRCT) we focus on quantifying their porosity at the sub-cm scale and relate these measures to sub-cm variations in permeability. Thirdly, despite of the extensive use of XRCT datasets in previous geological and engineering studies (Baez et al., 2013; Baniak et al., 2014; Capowiez et al., 2011; Kalender, 2006; Löwemark, 2003; Spaw; 2012), core-scale segmentation of geobodies has been limited to geological objects that exhibit high density contrast compared to the encasing matrix (i.e., pyrite or siderite vs. sandstone or mudstone; fractures, voids or large pores in carbonates or siliciclastic rocks). To the best of our knowledge, we are providing the first investigation directed at the segmentation and quantification of cm-scale geobodies with *slightly different, low-contrasting bulk density* (i.e., sandstone, wacke vs. mudstone). Finally, for the first time, 2D maps of mechanical properties are obtained on slabbed core and their controls inferred.

The effects of bioturbation on fluid flow through porous media are notable and have recently been addressed by several authors. For example, Gingras et al. (2002) studied porosity changes associated with dolomitized biogenic structures and generated three-dimensional distributions of selected fabrics using nuclear magnetic resonance techniques. These authors also performed relative dispersion measurements on dolomite-mottled limestone and inferred the existence of highly tortuous fluid flow paths within the samples studied. Meyer and Krause (2006) and Tonkin et al. (2010) investigated permeability and petrographic variations associated with visually bioturbated samples from outcrops and selected fossil traces in subsurface sandstone samples. Dabek and Knepp (2011) used computer modeling to simulate the effects of bioturbation intensity, lining, and burrow filling properties on permeability anisotropy. These studies demonstrate important relationships between trace fossil geometry, abundance, lining and filling properties, all of which have an effect on the average permeability of the rocks analyzed.

In this paper, whole and slabbed cores are examined as illustrated in the upper left frame of Fig. 1, but we focus on bioturbated rocks to determine the degree of variation and distribution of cm-scale lithology sub-components and corresponding reservoir and mechanical properties. For this purpose a combination of photographic and XRCT imaging is used along with profile permeability and microhardness testing. The investigated lithological categories are defined as "*elementary lithology components*" (ELCs) that, in our case, correlate very well with variations in colour in core slab photos (Fig. 1). ELCs can be defined operationally as discrete, lithologically-distinct rock elements that can occur at the dm- to sub-cm scale, as observed in Fig. 1. Each ELC can be segregated from the surrounding entities in terms of their color, chemical/mineralogical composition, texture (grain size, sorting, roundness), and cm-scale sedimentary structures.

In the following sections, a geologic overview of the study area is first provided, followed by a discussion of the samples used. Next the experimental protocols are reviewed for each measurement technique. Finally, experimental results are summarized and a discussion provided on the controls of reservoir and mechanical property variation at the microlithofacies scale in the studied tight oil reservoir.

Measurements used in this study were made on full-diameter, and slabbed cores (Fig. 1, left, and upper left-central panels) including XRCT and core scan/photography for evaluating ELCs distribution. Further details can be extracted at a higher resolution by means of X-ray micro computed tomography (XRμCT, upper central-right, and upper right panels), which is typically used for imaging bulk-density contrasts in core plugs (sampled from large whole core samples). Middle panel and lower left-central panel illustrates the use of backscattered electron imaging from scanning electron microscopy (BSE/SEM) for imaging micro- to nano-scale pore structures and their associations. These high-resolution images support our approach towards the identification and segregation of different ELCs from these highly bioturbated rock samples. Lower panel (right) illustrates use of transmission electron microscopy (TEM) for imaging nano-scale structures (Jiang et al., 1997). The darker areas represent pores and porous regions in the XRCT and BSE/SEM images. All images (except for TEM) were from tight oil reservoir samples of the Cardium Formation (Pembina field) in Western Canada.

Geologic overview of study area

The Cardium Formation hosts major light oil accumulations in the subsurface of the Western Canada Sedimentary Basin (WCSB) (Krause et al., 1987; Nielsen and Porter, 1984). Primarily multiple stratigraphic traps preferentially oriented in a NW – SE direction and dipping towards the SW represent the reservoir intervals (Joiner, 1991; Keith, 1985; Keith, 1991; Krause et al., 1987; Plint et al., 1986). These rocks were deposited as marine sediments along the western margin of the Western Interior Seaway during Late Turonian to Early Coniacian subages of the Late Cretaceous (Fig. 2) (Krause et al., 1994).

Deposition of the Cardium Formation is manifested as vertically stacked, but clinoforming shoreface successions, collectively capped by transgressive conglomeratic lags (Joiner, 1991; Keith, 1991; Krause and Nelson, 1984). Five major lithofacies or rock types typically occur within the coarsening upwards successions in Cardium Formation (Krause et al., 1987; Krause and Nelson, 1984), as described below:

(a) Lithofacies 1 (L1): dark grey mudstone and siltstone; shelf/offshore deposits
(b) Lithofacies 2 (L2): bioturbated, thin and very thin-bedded shale, siltstone, and very fine and fine-grained sandstone; offshore to offshore transition deposits
(c) Lithofacies 3 (L3): thinly-bedded shale, siltstone, and very fine and fine-grained wackes; offshore transition to lower shoreface
(d) Lithofacies 4 (L4): medium to thick-bedded, very fine and fine-grained sandstone; lower and upper shoreface deposits
(e) Lithofacies 5 (L5): conglomerate; erosional, transgressive lag.