



Influence of hydrocarbon injection on the compaction by pressure-solution of a carbonate rock: An experimental study under triaxial stresses



L. Neveux^{a,*}, D. Grgic^a, C. Carpentier^a, J. Pironon^a, J.P. Girard^b

^a University of Lorraine/CNRS/CREGU, GeoResources Laboratory, BP 40, 54501 Vandoeuvre-lès-Nancy, France

^b Total CSTJF, Avenue Larribau, 64000 Pau, France

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ABSTRACT

The preservation of good petrophysical properties (high porosity/high permeability) at great depth in carbonate rocks may lead to the existence of a deeply buried reservoir (DBR), a target of interest for the oil industry. One of the key processes controlling diagenesis of the burial environment is Pressure Solution Creep (PSC), an efficient compaction process responsible for the evolution of porosity and permeability in many carbonate reservoirs. In this experimental study, we examine the effect of i) the presence of oil in the pore space and ii) its timing of injection on the PSC process and the petrophysical properties of a carbonate rock. The experiments were performed using a flow-through high-pressure cell, allowing the simulation of the pressure/stresses and temperature conditions of a DBR. Multi-disciplinary data (mechanical, chemical, petrographical and petrophysical) demonstrate that, without oil in the pore space, the main diagenetic process is the PSC, a process reducing by three the initial porosity but having no influence on intrinsic water permeability. An early injection of oil prior to water circulation causes the inhibition of PSC by the coating of the grains, leading to the preservation of porosity. Conversely, a late injection of oil does not preserve initial porosity. The dataset obtained from these experiments show the importance of the timing of oil charging in a reservoir in the preservation of initial porosity at great depth by the inhibition of PSC. However, the coating of grains by hydrocarbons may also inhibit further diagenetic processes leading to a creation of secondary porosity at depth.

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1. Introduction

In carbonate reservoirs, porosity and permeability decrease with depth (Schmoker and Halley, 1982). However, there are many carbonated Deeply Buried Reservoirs (DBR) that display abnormally high values of porosity and permeability (Alsharhan and Magara, 1995; Caminatti et al., 2009; Machel, 2005). Such reservoirs represent an interesting new prospect for oil industry, even if they correspond to mainly unexplored territory. The accurate prediction of reservoir quality before drilling is even more important nowadays because reservoir exploration targets increasingly great depths. Therefore, the understanding of the key processes controlling diagenesis and preservation of reservoir qualities (i.e., good porosity/permeability) of carbonate rocks is a challenge.

Actually, under the high stresses and temperature conditions of DBR, many deformation mechanisms may potentially act during

burial and generate compaction process such as cataclastic flow, subcritical crack growth and Intergranular Pressure Solution (IPS). This last process, IPS, results in Pressure Solution Creep (PSC), which is a well-documented chemo-mechanical mechanism (Croizé et al., 2010; Gratier, 1993; Gratier et al., 2013; Spiers et al., 2003; Weyl, 1959; Zhang et al., 2010, 2011; Zubtsov et al., 2004) that involves dissolution of solids and removal of the dissolved matter by the way of diffusion through an interstitial solution. The mechanism is very significant in the case of carbonate rocks and is considered by many authors to be the main mechanism responsible for the decrease in petrophysical properties of reservoirs at great depth (Heydari, 2000; Lehner, 1995; Leythaeuser et al., 1995; McBride, 1989; Rutter, 1983; Sathar et al., 2012; Tada and Siever, 1989; Tamar-Agha, 2009; Weyl, 1959; Worden et al., 1998; Worden and Heasley, 2000). PSC is controlled by three major processes (dissolution, transport and precipitation), but their relative importance is not well known. It is commonly assumed that the displacement of aqueous fluids by petroleum prevents or significantly retards the precipitation of a diagenetic cement in a reservoir (Bloch et al., 2002; Epstein and Friedman, 1983; Feazel and

* Corresponding author. Tel.: +33 383684769.

E-mail address: lucille.neveux@univ-lorraine.fr (L. Neveux).

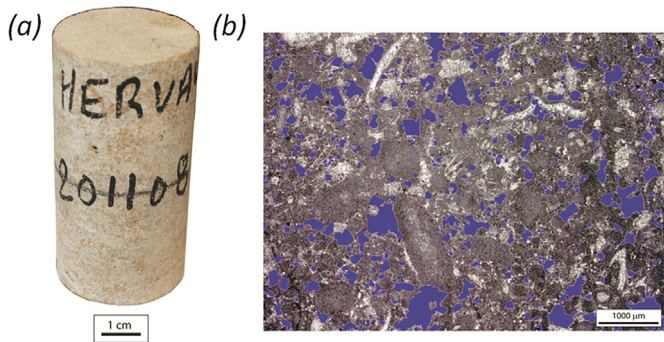


Figure 1. Cylindrical core sample (a) and thin section image (b) of Massangis limestone impregnated with blue resin in its natural state. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

Table 1

Chemical composition of Massangis limestone. Elements were analysed by ICP-ES.

| Oxides | Weight % |
|--------------------------------|---------------------|
| SiO ₂ | <0.5 |
| Al ₂ O ₃ | 0.09 ^a |
| Fe ₂ O ₃ | 0.35 ± 0.02 |
| MnO | 0.0044 ^a |
| MgO | 0.41 ± 0.04 |
| CaO | 54.27 |
| Na ₂ O | <0.03 |
| K ₂ O | 0.03 ^a |
| TiO ₂ | 0.005 ^a |
| P ₂ O ₅ | <0.05 |
| Loss on ignition | 43.4 |
| Total | 98.56 |

^a For Al₂O₃, MnO, K₂O and TiO₂, uncertainty is >25%.

Schatzinger, 1985; Friedman and Sanders, 1978; Healsey et al., 2000; Worden et al., 1998). The investigation of HC influence on diagenesis has been mainly focused on petrographical analysis of natural reservoirs, whether sandstones (Bjørkum et al., 1998; Gluyas et al., 1993; Marchand et al., 2001; Nedkvitne et al., 1993; Saigal et al., 1992; Sathar et al., 2012; Tamar-Agha, 2009; Worden et al., 1998) or carbonates (Cox et al., 2010; Feazel and Schatzinger, 1985; Healsey et al., 2000; Neilson et al., 1998; Worden and Healsey, 2000). Moreover, very few experimental studies have been performed on this subject and none, to our knowledge, were done on consolidated limestone. Indeed, such experiments that can be found in specialized literature were rather made on rock powders (Yasuhara et al., 2003; Zhang and Spiers, 2005; Zubtsov et al., 2004) that do not require high triaxial stresses representative of in-situ conditions to observe significant compaction. The remaining question is: what happens in the case of consolidated carbonate rocks? Has the PSC process a significant impact on the rock compaction? How the rock properties (deformation, porosity,

permeability, mineralogy) evolve under the high stresses representative of in-situ conditions? Has petroleum emplacement a significant impact on the PSC process? Even if many published diagenetic histories of oil fields show only one stage of HC emplacement and generally as the last diagenetic event (Haszeldine et al., 1992; Osborne et al., 1994), a more complex history, involving several stages of HC emplacement with or without an intermediate stage of leaching is conceivable (Deighton, 1996; Wilkinson et al., 2004). Indeed, filling and leaching of reservoirs over geological time periods is a common process (Bhullar et al., 1999; Healsey et al., 2000; Wilkinson et al., 2004). To investigate diagenetic processes acting during deep burial of carbonate reservoirs, we developed an experimental device allowing both the simulation of DBR pressure/stresses/temperature conditions and the circulation of different fluids (natural meteoric water, hydrocarbon) in limestone core samples. Triaxial multi-step creep tests are performed on these samples and the influence of the timing of hydrocarbon (HC) injection on the chemo-mechanical behaviour of limestone was tested. This multidisciplinary approach implies the analysis of creep deformations, chemistry of pore fluids, petrographical and petrophysical properties of tested samples.

2. Experimental setup and methods

2.1. Description of the initial rock

A Bathonian bioclastic limestone, sampled in the active quarry of Massangis (Burgundy, France), was used for the experiments. This limestone contains only early marine cements, and so enables to focus on the effects of deep diagenesis. Major grains are ooids, pellets and bioclasts (Fig. 1b). A micritic matrix is found between grains, suggesting a microbial origin (Hillgärtner et al., 2001) (Fig. 1b). This limestone belongs to the Oolithe Blanche Formation of the Paris Basin. This formation is locally a hydrocarbon reservoir (Casteleyn et al., 2010), so it can be assumed that it's an oil-wet rock. Samples were analysed by ICP-ES (Inductively Coupled Plasma – Emission Spectrometry) and their average chemical composition is presented in Table 1. The presence of magnesium in the chemical composition of Massangis limestone may come from either the presence of a few crystals of Mg rich calcite or from the presence of dolomite crystals. Cathodoluminescence study has been performed on thin sections of initial samples, and no dolomites were found. However, the heterogeneity of the Massangis formation could mean that in some samples there are some rare dolomites but they were not seen. Indeed, it must be observed that the Oolithe Blanche formation (the formation to which the Massangis limestone belong to) presents an event of dolomitization followed by one of dedolomitization of this unstable dolomite (Purser, 1989). The presence of iron in the chemical composition of Massangis limestone comes from the presence of iron oxides and some pyrite crystals.

We tested petrophysical properties of the Massangis limestone. Table 2 presents the results of two Purcell tests (mercury intrusion

Table 2

Petrophysical properties of Massangis limestone: initial sample and samples after Experiments I, II and III.

| Sample | Hg porosity (%) (2 measurements) | | | Density of the solid skeleton ρ_s (g/cm ³) ^a | Density of the dry rock ρ_d (g/cm ³) ^a | Total porosity (%) $nt = 1 - \rho_d/\rho_s$ | Intrinsic water permeability k |
|----------------|----------------------------------|-----------|------------|--|--|---|---|
| | Total | Free | Trapped | | | | |
| Initial sample | 18.6 ± 1.2 | 5.9 ± 1.1 | 12.7 ± 2.2 | 2.69 | 2.17 | 19.4 | 25 mD 2.5 × 10 ⁻¹⁴ m ² |
| Experiment I | 8.8 ± 3.2 | 2.5 ± 1.2 | 6.3 ± 2.1 | 2.79 | 2.16 | 22.8 | Cf. Figure 2 |
| Experiment II | 14.4 ± 0.2 | 4.2 ± 1.2 | 10.2 ± 1 | 2.74 | 2.23 | 18.7 | Cf. Figure 2 |
| Experiment III | 8.4 ± 0.8 | 2.1 ± 0.1 | 6.3 ± 0.8 | 2.77 | 2.20 | 20.6 | Cf. Figure 2 |

^a Density measurements were conducted by helium pycnometer.

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