AN INTEGRATED APPROACH TO ESTIMATE THRESHOLD CAPILLARY PRESSURE FROM CORE AND LOG DATA

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ABSTRACT

Threshold capillary pressure (P_{cd}) is an important parameter to characterize in the context of reservoir production, basin modeling and geological storage (natural gas or CO_2). Various approaches exist to measure this parameter in the laboratory. For caprocks, their extremely low permeability values makes it difficult to multiply the number of measurements in order to directly obtain a large scale picture of the structure confinement property (path of less capillary resistance). It is therefore very attractive to use P_{cd} correlations anchored on properties that can be estimated from the logs to conduct this type of analysis.

This paper presents an example of such integration methodology in a heterogeneous caprock. The first part describes how a revisited correlation was derived using HPMI (High Pressure Mercury Injection) data that were obtained on old, poorly preserved samples of cores. Corrected P_{cd} values (from interfacial tension, IFT) were obtained directly from the HPMI curve and the associated permeabilities were deduced by standard estimation methods (Swanson et al., 1981, Thomeer et al., 1983, Kamath et al., 1992). In the second part, the results were then compared with published correlations (Thomas et al., 1968, Monicard et al., 1975), with well documented experimental published data and also with results of new experiments obtained on recently acquired preserved fresh cores. It has enabled us to set up and strengthen a revisited correlation which appears to be representative and applicable over a wide range of permeability. The third part describes how the new correlation was used in combination with relevant logs to obtain a large scale description of P_{cd}.

The main result of this study is a new correlation that integrates rock properties variations in the estimation of P_{cd}. It underlines the importance to integrate cores and logs data, using correlations anchored on representative core measurements.

INTRODUCTION

Evaluating sealing efficiency of caprocks and maximal gas overpressure are a key criteria in the selection of a geological structure for underground storage (natural gas or CO_2). This leads to assess the maximum injection operating pressure gradient to avoid migration through the caprock into overlying permeable formations. The threshold capillary pressure characterizes the ability of a porous medium saturated with a wetting phase to block the flow of a non-wetting phase. Its value corresponds to the minimum pressure difference between the two phase to promote an invasion of the non wetting fluid in the porous medium. It is directly related to the size of the largest pore throat in the porous medium and can be calculated using the following equation:

Laplace-Young $$P_{cd} = \frac{2\sigma \cos\theta}{R_{throat}^{max}} \qquad (1)$$

Where P_{cd} is the capillary pressure of a rock with the largest throat radius of the rock (R_{throat}^{max}), the gas/water interfacial tension (σ) and the contact angle between the gas/water interface and the rock (Θ). Caprocks have high capillary threshold pressure and low permeabilities, due to very fine pore and pore-throat sizes.

The purpose of this paper as any reservoir characterization is to define a parameter (P_{cd}), that can be integrated with a geological model to display the caprock properties in three-dimensional space. To allow this, cores capillary pressure data must be related to other reservoir rock properties, using wireline logs that are calibrated on core measurements. The first part of this paper presents the basis of the method and how well logs data and key core measurements (porosity, permeability) can be combined to obtain a P_{cd} log. In the second part, the methodology is applied in a real case using mercury porosimetry obtained on old poorly preserved cores to calibrate the model. The P_{cd} log calculated from this approach is then compared with relevant P_{cd} data recently obtained on fresh cores in the third part. This enables us to draw some conclusions about the potential of the proposed approach to obtain early relevant estimation of confinement properties even when only old core material is available.

METHODOLOGY

Basis of the method

We provide a methodology, using empirical relationships, to produce a capillary pressure log in three steps. The technique can be applied to wells that have no measured capillary pressure but for which core porosities, horizontal (K_h) and vertical (K_v) permeabilities have been measured on field cores. This method provides a direct solution for predicting vertical and lateral variations in reservoir rock properties that are related to variations in capillary pressure properties. The following approach was followed (Figure 1).

First, a total porosity log is obtained using available log data for porosity computation (neutron, density, sonic). Then, core relationships (Ø vs K_h and K_h vs K_v) are used to determine horizontal and vertical permeability logs. Finally, a P_{cd} log is applied by using an empirical P_{cd}-K_v relationship.

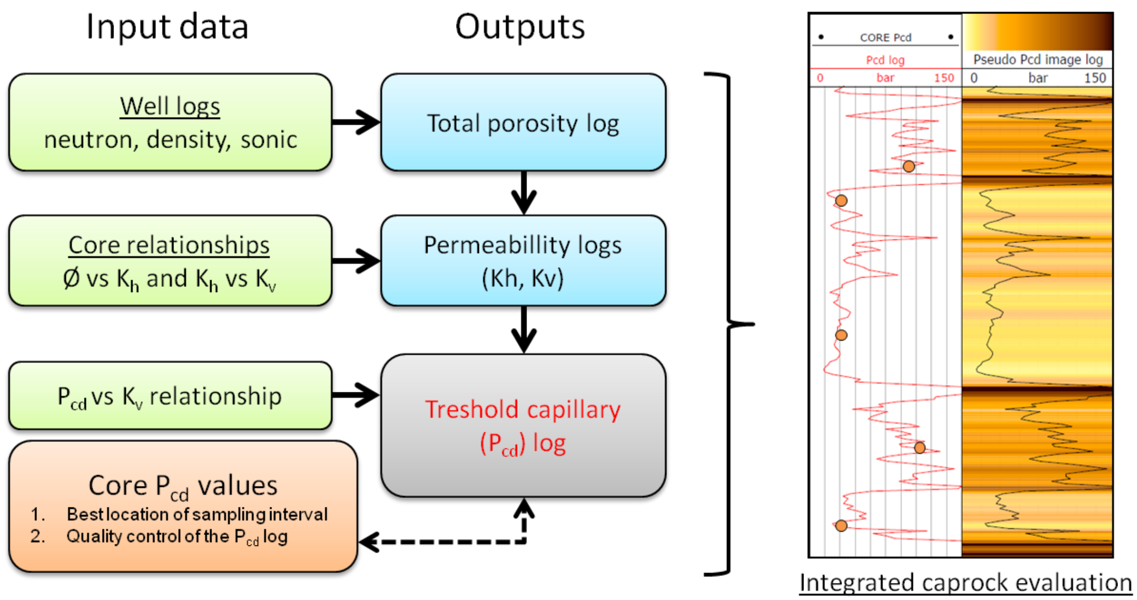

Figure 1 : workflow to construct a threshold capillary pressure log from well log data and core measurements.

Various P_{cd}- K_v relationships have been suggested in the literature :

Thomas et al. (1968) $$P_{cd} = 7.37 \times \left(\frac{1}{Kv}\right)^{0.43} \quad (2)$$

Monicard et al. (1975) $$P_{cd} = 9 \times \left(\frac{1}{Kv}\right)^{0.5} \quad (3)$$

Where P_{cd} is the threshold capillary pressure (psi) and K_v the vertical permeability (mD).

Application made in this study

In this study, we had initially only old poorly preserved cores. Therefore the data needed to calibrate the relationships were derived from mercury porosimetry measurements. Porosity and P_{cd} (after correction) were obtained directly whereas the permeability was estimated using available methods in the literature (Thomeer et al., 1983; Swanson et al., 1981, Kamath et al., 1992). This has made possible to calculate a preliminary P_{cd} log on a recently drilled well where fresh preserved cores were retrieved. This P_{cd} log was first used as a guide to sample the best locations. The new P_{cd} measurements obtained from these samples have then been used to quality control a posteriori the representativity of the P_{cd} log.

P_{cd} log from old core data

<u>Core description</u>

At the beginning of the study, existing cores were recovered several decades ago during a former drilling campaign to assess a potential area. Two types of formation were represented on the caprock: clay rich silty and bioclastic marlstone (rock facies 1), shown as the dominant lithology on well log/core data and tight carbonates (rock facies 2).

By examining the thin sections, we can see a lack of apparent macro porosity (larger than 5 microns) on both rock facies, implying dominance of mesoporosity (0.5 to 5 microns) and microporosity (less than 0.5 microns). Low pore throat sizes with high entry capillary pressure values are expected with associated low permeabilities. Some areas contain a significant amount of bioclasts (about 50%) beside clays and the microstructure can be also quite complex on carbonate samples.

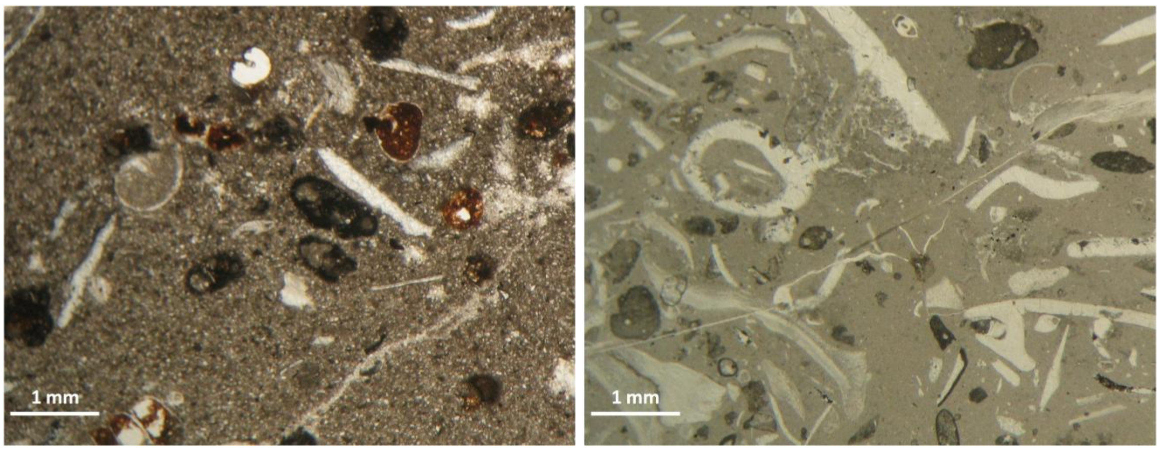

Figure 2 : Thin-sections photomicrograph of two caprock facies, clay-rich silty and bioclastic marlstone (left) and tight carbonate (right).

Carbonates containing multiple pore systems present challenges to obtain representative capillary pressure data (Almarzouqi M. et al, 2010). The pore geometry can be highly variable, with zones containing significant amounts of macroporosity interspersed with zones dominated by meso or microporosity.

Mercury porosimetry measurements to calibrate relationships

Mercury injection is a relatively quick and low cost technique to obtain capillary pressure data. Sixty-two old core samples recovered from three old wells were prepared for testing with high pressure mercury injection (HPMI) (also referenced as mercury injection capillary pressure (MICP) in the literature), which offers a rapid method of developing capillary pressure curves to very high pressure. The mercury method also has the advantage to consume a small volume of rock (often only fragments of rocks were available). It involves injecting mercury in a step-wise manner into a dry core sample initially placed under vacuum. The threshold P_c is obtained from the mercury intrusion pressure after interfacial tension corrections (IFT). The displacement of the mercury can therefore be used to calculate the bulk volume of the rock, the porosity and the associated permeability, deduced from estimation methods (Thomeer et al., 1983; Swanson et al., 1981, Kamath et al., 1992; Comisky et al, 2007). Some limitations of the mercury porosimetry method (lack of confining pressure, samples preparation procedure without alteration of the pore structure...), can make this approach very inaccurate but it is very adequate to collect early "trends" when no other data under in-situ conditions are available (Egermann et al., 2006).

Result of HPMI method: P_{hi}-K relationship

The evolution of the volume of mercury injected (depending on the pressure) gives direct access to the entry pressure and the pore volume. Figure 3 (left) shows an example of the distribution of pore size that can be deduced from one measurement on a tight carbonate caprock sample. In this case it gives an average size of 0.03 microns which confirms the very tight nature of the environment. The Figure 3 (right) shows a plot of the cumulative intrusion curve as a function of pressure for the same carbonate sample. Significant mercury intrusion occurs only above pressure of 3000 psi.

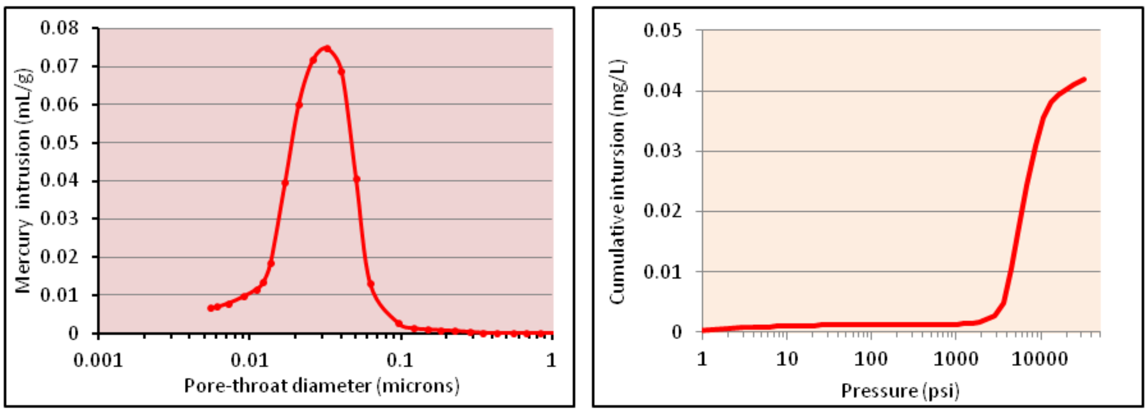

Figure 3 : Pore throat size (left) from the cumulative mercury intrusion (right) of a tight carbonate sample.

We chose the Swanson's model to derive permeability estimates (Swanson et al., 1981). The porosity, calculated from the total amount of Hg injected during the measurement and the permeability estimated on sixty-two samples, provides a fair correlation (Figure 4). Although there is a wide scatter in porosity and permeability data for high values that can be related to an increasing clay content of badly preserved samples.

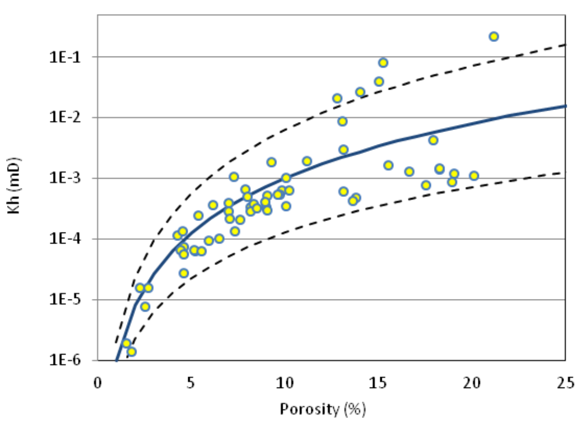

Figure 4 : Core porosity and permeability relationship (HPMI measurements).

Result of HPMI method: P_{cd}-K_v relationship

Threshold capillary pressure results from HPMI method were compared with the two correlations previously presented and commonly used by petroleum industry (because of solid experimental validation) relating threshold Pc and vertical permeability (Kv) (Thomas et al., 1968; Monicard, 1975) in Figure 5.

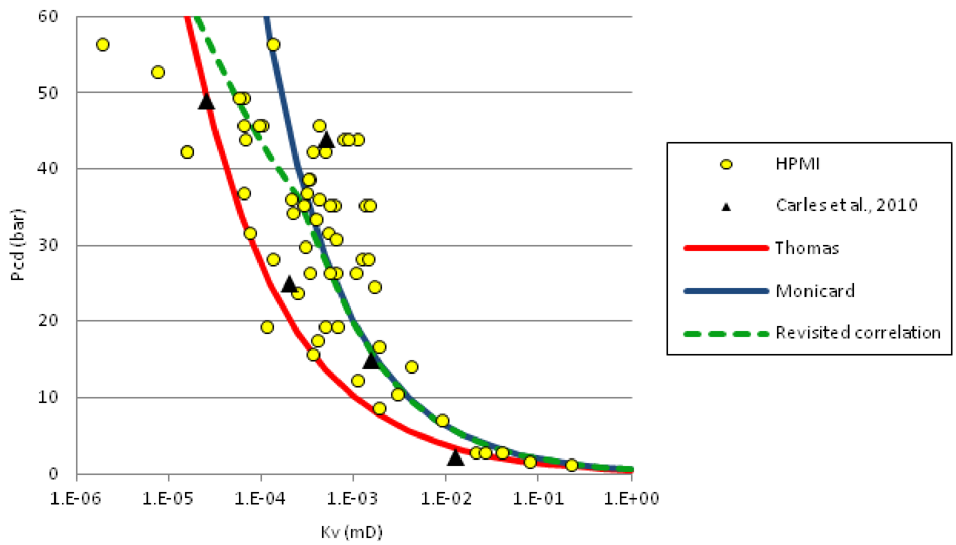

Figure 5 : The revisited P_{cd} vs K_v correlation

At rather higher permeability values, the Monicard law appears to better represent the data which seems better representative. However, the measurements corresponding to progressively lower permeability seem better represented by the model of Thomas. This feature is certainly due to the fact that Thomas's law was mainly anchored on very shaly and very low permeability samples.

A composite model initially anchored on Monicard's law, then on Thomas's law was introduced to better capture this trend. The permeability value (K>0.00033 mD) from which the new correlation deflects from Monicard's law to the Thomas's law is defined visually on the plot. The revisited correlation is presented as:

$$P_{cd} = a \times \left(\frac{1}{K}\right)^b \tag{4}$$

With the following input parameters:

- a=9 and b=0.5 for K>0.00033 mD,
- a=100 and b=0.2 otherwise.

The new correlation was also compared with other published data obtained on tight carbonate study (Carles et al., 2010). It shows a similar trend to what was observed with our samples (Figure 5).

Core to log integration

Determination of a porosity log is the first important part before following the workflow proposed in Figure 1. In our study, the porosity is estimated from a combination of porosity logs, in order to correct for variable lithology effects (clay, silt and carbonate). The neutron density log combination, commonly used in the industry, is chosen to determine the porosity by taking an average of the two log readings:

Neutron-density porosity $$\varnothing = \sqrt{\frac{\varnothing_n^2 + \varnothing_d^2}{2}} \quad (5)$$

Where $\varnothing_n$ and $\varnothing_d$ are neutron and density total porosity.

Downhole logging tools and laboratory techniques are sensitive to different portions of the pore system. Therefore in practice, available wireline logs for this study are insufficient to distinguish clay bound water and capillary bound water associated with shale micropores. So, total porosity is considered and represents an approximation. A simple crossplot of the two measurements from one well shows in Figure 8 a reasonable agreement between core (CPOR) and log (PHIT) porosity suggesting HPMI total porosity is approximately equivalent to the total porosity log derived from neutron and density tools.

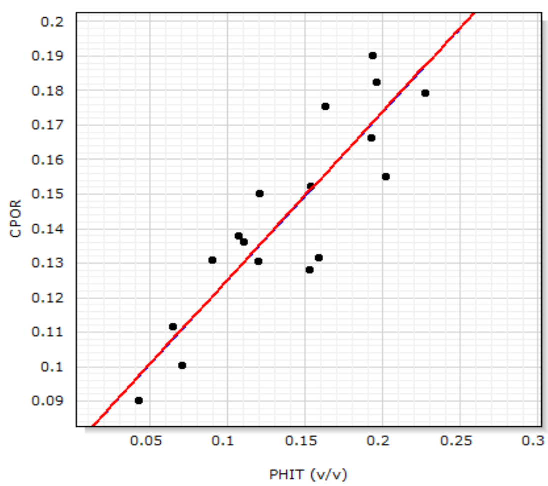

Figure 6: HPMI core porosity versus the total porosity log computed on the same well.

Figure 7 shows the P_{cd} log estimated for a new well with the calibrated relationships. A pseudo image log (FMI type image) has also been generated, using the computed log, to highlight caprock layers with very good confinement properties. As new fresh preserved cores were acquired on this well, this a priori P_{cd} log was used to steer the sampling strategy in order to collect laboratory data from the different facies in term of confinement properties. This has therefore also provided to us a kind of blind test very useful to assess the added value of the proposed approach to provide default P_{cd} data or to populate P_{cd} data in non cored wells.

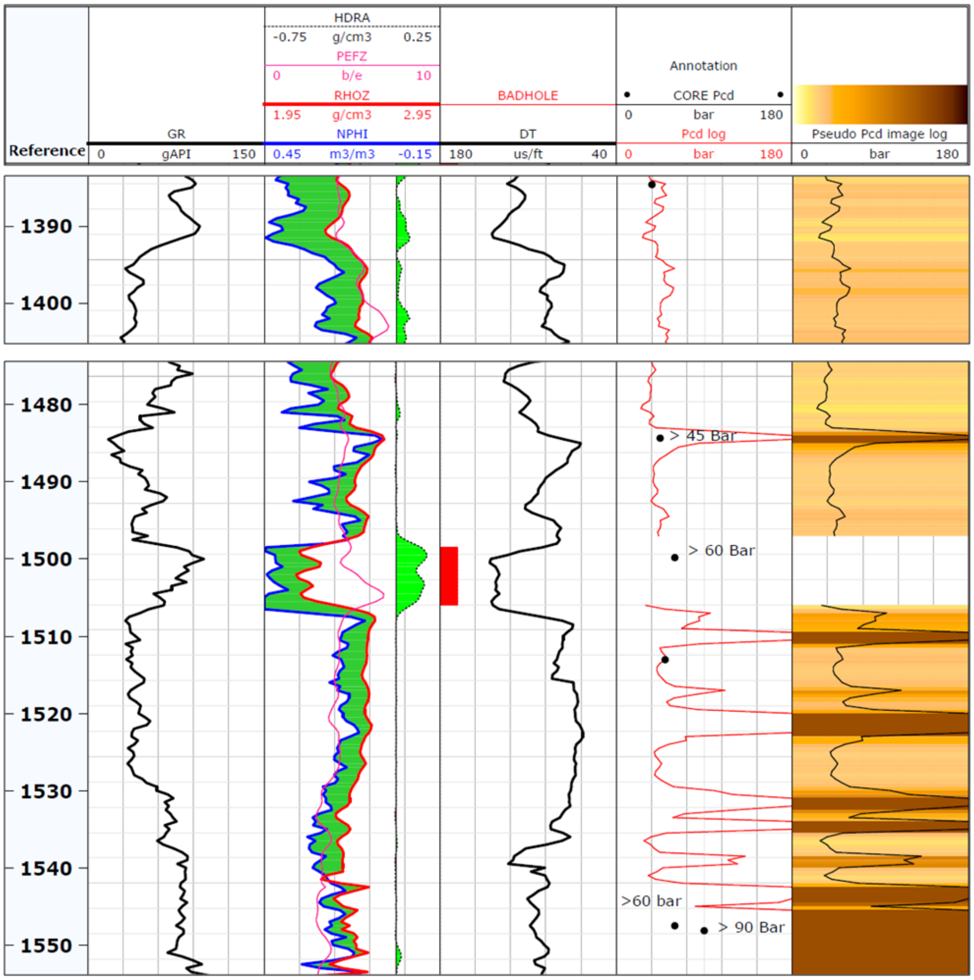

Figure 7: Example of a threshold P_c log calculated for a well.

Quality control of P_{cd} log using standard method on fresh cores

Experimental Results

There are different methods for determining threshold capillary pressures in laboratory (Boulin et al, 2012). The most commonly used being:

- Standard method: based on the step by step approach (Al-Bazali et al., 2005). Gas is in contact with the sample surface at the inlet. Initially gas pressure is equal to pore pressure. Then gas pressure increases by steps. Each pressure amplitude and step duration depends on the accuracy required on P_c and the sample permeability. When the capillary pressure (gas pressure minus pore pressure) is higher than P_{cd}, water is displaced out of the sample. The pump placed downstream provides this information.
- Dynamic method: gas injection pressure imposed just above the value of the entry pressure. The displacement pressure is deduced from variations in water

production output (Egermann et al., 2006). This method is fast but requires an a priori assessment of the value of P_{cd}.

- <u>Residual method</u>: although simple to implement, it has been shown that this method consist in balancing two pressure vessels at the inlet and the outlet through the sample, leading to an underestimation of the displacement pressure (Hildenbrand and al., 2002).

As part of this study, the standard method was chosen to determine the values of P_{cd}. It was conducted on seven 1½″ diameter cylindrical core plugs taken in the vertical direction of preserved cores from a recent well. A schematic description of the device is provided in Figure 8. The measurements were made using the following protocol. The experimental setup was first validated on an old core, well consolidated, tight carbonate sample (sample 1).

The experimental set up used to perform this experiment is composed of a horizontal cell to confine the sample, fitted at the outlet with a capillary water filled tube, which measured the water going out of the sample. The monitoring is based on the progression of the meniscus located at the air/water interface. This approach provides a very good sensitivity even with a low water production. The pressure of effective stress (also called confining pressure), calculated on the side of the sample, is applied to the sample in an isotropic way. All measurements were made using a net confining pressure. The nitrogen pressure is applied to the front face of the sample with typical pressure increment of 10 bar. The experiments were usually pushed to a pressure of 60-70 bar with the exception of the last sample where the maximum applied pressure was 90 bar.

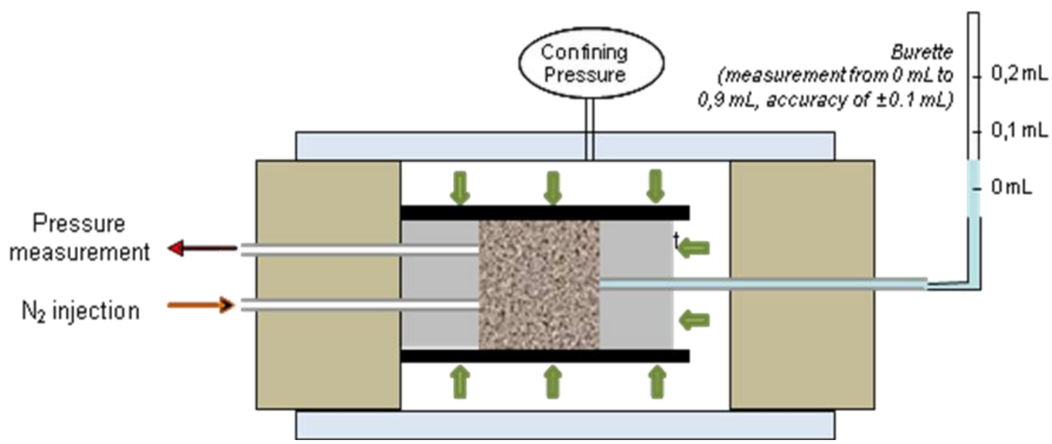

Figure 8 : Schematic of the experimental setup.

Pressure breakthrough is confirmed if and only if: gas is observed at the output of the sample, the applied input pressure drop substantially, and a slope change is observed on the cumulative water production. Figure 9 (left) shows, for one sample representing rock facies one, the different levels of gas pressure imposed in entry (dashed curve), while water production (pushed by gas) is measured at the output (curve points). Once the gas breakthrough is established, the gas outlet production line was connected to a returned separator initially filled with water. This device is very efficient to record accurately small volumes of gas production, in the order of the cubic centimeter, to measure effective gas permeability after breakthrough.

During experiment, samples of rock facies one (clay rich silty and bioclastic marlstone) were proved deformable and subject to slow creeping. This feature is observed on Figure 9 left (1) where water production was observed for a shaly sample without gas detection at the outlet. This water corresponds to the deformation of the sample under the influence of the confining pressure (confirmed on some samples by water production recorded in output without gas pressure at the outlet). Water production after a capillary breakthrough by gas is characterized by a rapid change in the slope (2) related to the increase of input pressure and bubbles gas detection at the outlet ($P_{cd} \approx 50$ bar).

Figure 9 right shows an example of creeping when the confining pressure was initially applied on the sample. This plot clearly illustrates a displacement of the meniscus without any gas pressure applied at the inlet. In term of experimental protocol, it is therefore recommended to wait for stabilization after change in the confining pressure before applying gas inlet pressure increments, in order to dissociate the two mechanisms that can lead to a meniscus displacement.

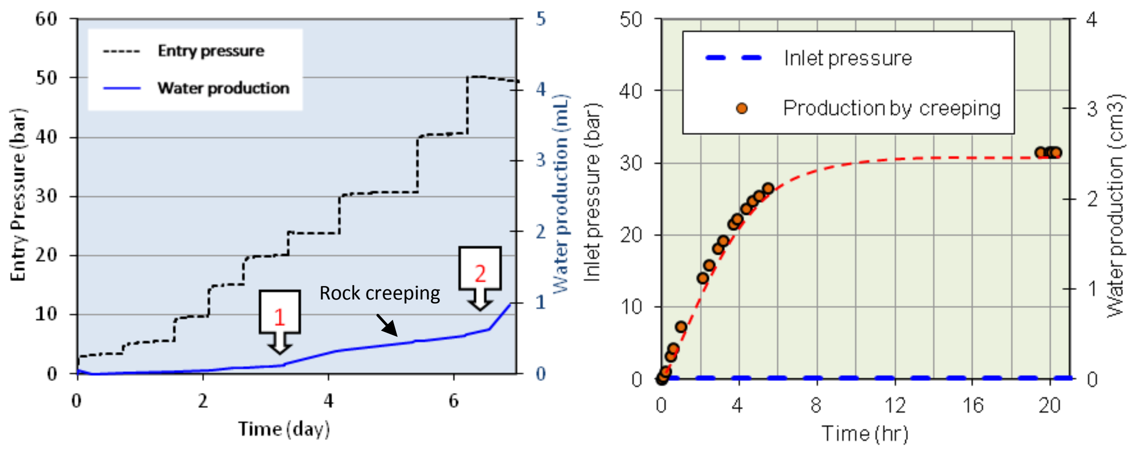

Figure 9 : Monitoring of input pressure levels and water production of one sample (rock facies 1), and example of creeping effect (right)).

The main results of the standard method experiments are summarized in Table 1 with the effective gas permeability (Kgas) in the experiments where gas breakthrough has been observed. The measurement was carried out with the permanent method, by imposing a differential gas pressure on the sample and measuring the corresponding flow. Klinkenberg corrected permeability were also computed, to correct for gas slippage effect that may dominate, and yield an estimate of the equivalent liquid permeability.

Results shows good confinement properties of caprock samples with particularly high P_{cd} values in the basal part (samples 7 and 8). To obtain a breakthrough, the last experiment (sample 8) was pushed up to 90 bar, but despite this value, no gas was observed at the outlet. The associated effective gas permeabilities were found very low (from 0.003 to 0.03 µD) which is in good agreement with the expected range of permeability considering the measured P_{cd} values.

Table 1 : Summary of results using standard method (*Old core sample for experimental setup validation).

		Core standard method (direct measurements)			Log method
Sample	Rock facies	P_{cd} (bar)	Kgas (µD)	Kgas (µD) *Klinkenberg-corrected*	P_{cd} log (bar)
1	Tight carbonate*	40	0.0019	0.0031	-
2	Clay rich marlstone	48	0.0148	0.0247	> 40
3	Clay rich marlstone	36	0.024	0.037	30 - 40
4	Tight carbonate	> 45	-	-	> 100
5	Tight carbonate	> 60	-	-	> 100
6	Tight carbonate	50	0.0129	0.0137	50
7	Tight carbonate	> 60	-	-	> 100
8	Tight carbonate	> 90	-	-	> 100

Comparison with a priori P_{cd} log

A blind test of the representativity of the P_{cd} log was obtained using the conventional (standard method) P_{cd} measurements (Table 1). It shows quite a good correlation especially for intervals not affected by hole washouts (without badhole indication). It is interesting to note that all the measured points are in good agreement with what was anticipated from the P_{cd} log and especially the large variability of the values. It enables to confirm from this integrated study that the confinement properties of this caprock results from both a baseline P_{cd} value between 30 and 40 bar and several metrics layers with extremely good confinement properties at the bottom of the caprock (>100 bar).

CONCLUSIONS

Several conclusions can be drawn from this study. A methodology was proposed to integrated P_{cd} core data and log data to obtain a log of P_{cd} value. It was successfully applied in a real case using mercury porosimetry data obtained on old cores to calibrate the various relationships. Having such P_{cd} log on a new well was very useful to steer the sampling strategy in new fresh preserved cores in order to investigate in the laboratory the variability of the caprock in term of confinement property. Finally the comparison a posteriori of the representative P_{cd} measurements from fresh cores with the a priori P_{cd} log was very good. This suggests that this approach could consist in a fair estimation approach to assess the confinement properties of a structure when scarce data are available.

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