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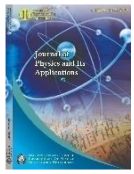

The Influence of Capillary Pressure on Permeability in Rock Samples Using the Mercury Injection Capillary Pressure (MICP) Method

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ABSTRACT

The Mercury Injection Capillary Pressure (MICP) method to measure capillary pressure has become a crucial technique for characterizing the porosity and permeability of reservoir rocks. This study aims to assess the impact of capillary pressure on the permeability of two rock samples from the Bangko and Telisa formations in the Central Sumatra basin. Measurements were conducted utilizing the Autopore V 9600 instrument, which employed mercury as the injected fluid into the two rock samples, under pressures reaching up to 60,000 psi. These pressures are classified as capillary pressure. The data obtained were analyzed through Drainage curves to elucidate the relationship between capillary pressure and permeability. The results derived from the Drainage curves indicate that the A1 rock sample from the Bangko formation has medium permeability, with displacement pressure (Pd) of 10.4871 psi. In comparison, the A2 sample from the Telisa formation has low permeability with Pd of 516.6259 psi. The increase in capillary pressure resulted in a decrease in water saturation and an increase in the intrusion of the non-wetting fluid (mercury), particularly in samples with better permeability. This finding suggests that lower Pd values indicate better pore connectivity, which correlates with increased permeability. Highlights that the MICP method provides profound insights into the relationship between capillary pressure and the ability of rocks to transmit fluids, as well as the significance of pore geometry and distribution in influencing the permeability characteristics of reservoir rocks.

1. Introduction

Capillary pressure is a crucial physical parameter in determining reservoir rocks' physical and mechanical characteristics in the oil and gas industry. Capillary Pressure in the oil and gas industry is a physical parameter that is the difference in pressure between the two phases of a fluid that does not mix in the pores of the rock. The existence of two or more fluid phases in rock pores is caused by the process of fluid migration from one rock pore to another. The pressure of the fluid that migrates from the original rock to another will give a difference in pressure within the rock.

The ability of fluids in rocks to migrate is driven by a physical parameter of the rock called permeability. This is because permeability indicates the ability of a rock to flow fluids. Capillary pressure parameters in rocks can provide important information about the ability of a reservoir to store fluids affected by the pore size of a rock (porosity) and drain fluids affected by the permeability value of a rock. The size of the pores of reservoir rocks can often be attributed to permeability.

The relationship between rock pores and permeability can be seen from capillary pressure analysis. In general, if the size of the pores of the rock is large, the permeability of the rock is large. However, the results of the capillary pressure analysis show that the permeability value does not only depend on the pore size but also depends on the pore geometry of the rock, the distribution of pores in the rock [1–6] and rock pore connectivity [7].

Mercury injection capillary pressure (MICP) is a commonly used technique to measure porosity, pore size distribution, and injection pressure that affect mercury saturation in different types of rocks. In the MICP Technique, mercury is considered a non-wetting phase fluid that can push air. This condition is called wetting phase fluid. Therefore, mercury injected into rock samples taken from Oil and Gas fields can be assumed to be hydrocarbons (crude oil or natural gas) and wetting phase fluids are assumed to be rock formation water. The results of the measurements using the MICP technique can be used to estimate the permeability of rocks [1], [8], [9].

During mercury injection at lower pressures, larger pores will be filled first during injection, so that more effective and efficient mercury injection is present at lower pressures [10]. This is known by plotting the capillary pressure versus water saturation and it can be seen that, for a decrease in permeability, there is a corresponding increase in capillary pressure at a constant water saturation value [11].

Measurements using the Mercury Injection Capillary Pressure (MICP) method were carried out by injecting mercury fluid into the rock sample using the Autopore V 9600 tool (see Fig. 1). There are two measurements, namely with low pressure and high pressure, whose capillary pressure is up to 60.000 psi. At the time of measuring the capillary pressure, two curves are produced, namely the Drainage curve and the Imbibition curve (Fig. 2).

Fig. 1: Autopore V 9600 tools (documentation taken in LEMIGAS)

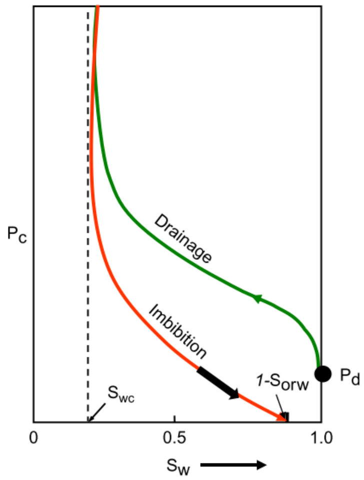

Fig. 2: Capillary Pressure Hysteresis Curve [12]

In this measurement process, the rock sample or Coring is a rock sample that does not contain oil (with a water saturation value of 100%). This sample is then placed into the Autopore V 9600 tool, which injects mercury fluid into the rock sample, starting from the lowest pressure and increasing to a maximum pressure of 60,000 psi. The mercury fluid is assumed to represent an oil fluid (non-wetting phase) present in the field, while the air occupying the pores of the rock sample is assumed to be water (wetting phase). Once the pressure reaches its maximum, the rock sample becomes saturated with mercury fluid, causing the Sw value to decrease. This condition is said to be a Drainage condition. After the rock sample is filled with mercury fluid, there is a decrease in capillary pressure where the mercury fluid is pushed by the air that enters the rock sample so that the mercury fluid is replaced with air. This condition is referred to as the Imbibition condition. The width of the Drainage and Imbibition curves separation can indicate the permeability of the rock sample, whether low or high permeability of the rock sample. The transition zone refers to the vertical thickness where two fluids are flowing (Fig. 3). This phenomenon is attributed to the difference in the Displacement Pressure (Pd) values, which represent the critical capillary pressure or capillary entry pressure where the pores of the rock sample begin to be filled by mercury fluid (non-wetting phase) [6], [10], [13], [14].

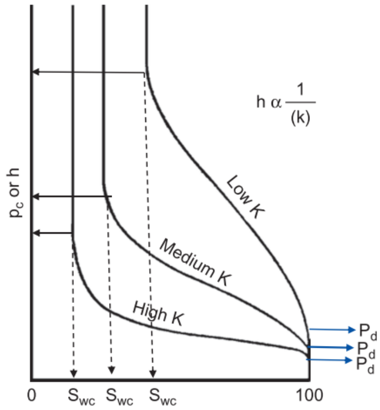

Fig. 3: Drainage Variation Curve with Absolute Permeability [12]

The measurement method using the MICP method uses the Washburn equation [7], [15], where the capillary pressure is converted to the diameter of the pore cavity of a rock which is written the equation as follows:

$$P_C = -\frac{4\sigma \cos\theta}{d} \tag{1}$$

where Pc is the capillary pressure (MPa), d is the diameter of the rock pore cavity (nm), σ is the surface tension of the mercury that is of value 480×10^{-3} N/m, and θ is the contact angle of the mercury fluid that is valued 140°.

The diameter of the pore cavity in the rock affects the value of the porosity of a rock, whereas the value of the porosity of the rock will affect the value of the permeability of the rock. The relationship between capillary pressure, permeability, and porosity parameters written with the following equation [2]:

$$P_C = A\left(\frac{K}{\emptyset}\right)^{-B} \tag{2}$$

where *Pc* is the capillary pressure of the measurement of the rock sample (coring), K is the permeability of the rock (mD), Ø is the porosity of the rock (%), A and B are the constant values obtained from the results of measurements in the research conducted by Kwon and Picket where the equation was used in the research conducted by Saafan and his team in 2023 [2].

MICP method was conducted in this research to define the influence of Capillary Pressure on Permeability in rock samples whereas become the reservoir rocks of Oil and Gas. This method was expected to show the aim of this research through the result of Drainage Variation Curve versus Absolute Permeability.

2. Methods

The methodology employed in this research begins with the collection of primary data at the Oil and Gas Institute Coring Analysis Laboratory (LEMIGAS) located in Jakarta. The research utilizes two rock samples obtained from distinct wells at varying depths, yet both are located within the same basin, specifically the Central Sumatra Basin. The first rock sample (sample A1) is derived from the Bangko Formation, which is characterized by a predominance of sandstone and shale layers, thereby classifying Sample A1 as a reservoir rock. Conversely, the second rock sample (sample A2) is sourced from the Telisa Formation, which is predominantly composed of shale with thin interbeds of sandstone and carbonate rock (refer to the red box in Fig. 4). Consequently, Sample A2 is identified as a seal rock. [16], [17].

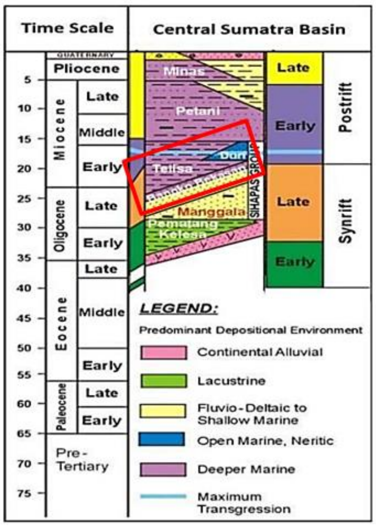

Fig. 4: Stratigraphy of the Central Sumatra Basin [16]

Samples A1 and A2 were analyzed by Special Core Analysis (SCAL) to obtain basic data on the form of porosity and permeability which are physical properties of rocks (see Table 1).

Table 1: Basic Data Result of SCAL

Sample	Depth ft	Porosity Ø	Permeability mD
A1	1xxx.x	23.67	17.43
A2	4xxx.x	17.45	0.092

2.1. Capillary Pressure Measurement

After obtaining basic data from SCAL, the two rock samples commenced the measurement of capillary pressure utilizing the MICP method. During this measurement process, two rock samples or Coring are rock samples that do not contain oil (indicating a Water Saturation value of 100%), were placed into the Autopore V 9600 apparatus. This tool facilitates the injection of mercury fluid in the rock sample from the lowest Capillary Pressure to a maximum capillary pressure of 60,000 psi. In this measurement, the surface tension of mercury is a critical parameter, alongside a contact angle of 130° for the mercury fluid. The duration of this testing process ranges from approximately 3 to 6 hours, depending on the permeability of the rock, the smaller the permeability, the longer the injection mercury testing process. The outcomes of this measurement method generate two curves for each sample analyzed in this research (see Fig. 5 and 6).

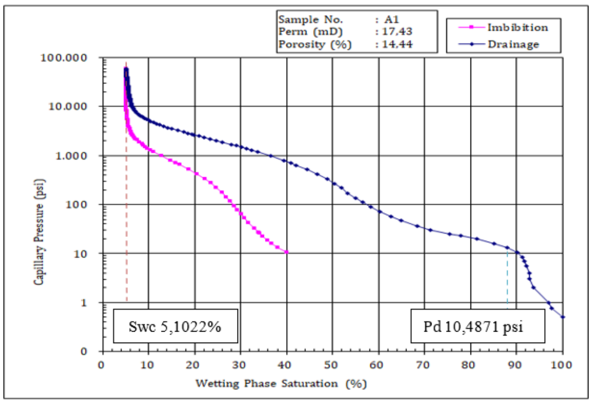

Fig. 5: Capillary Pressure Curve to Wetting Phase Saturation in sample A1.

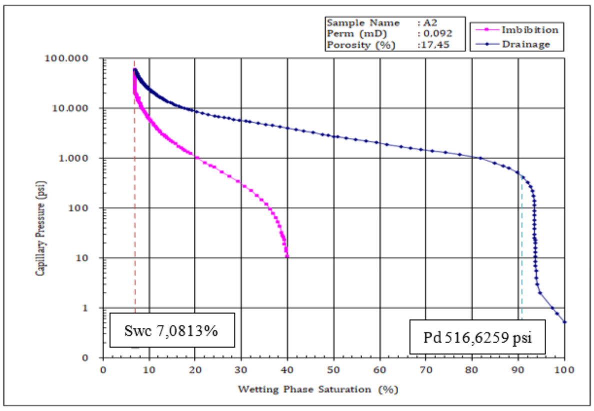

Fig. 6: Capillary Pressure Curve to Wetting Phase Saturation in sample A2.

2.2. Determination of Permeability Quality

In Fig. 5 and 6 in this research, the Drainage curves of sample A1 and sample A2 were combined (see Fig. 7) to obtain the quality of permeability by looking at the curve trend of the two samples which is the same as the permeability trend in the Drainage condition in Fig. 3.

3. Result and Discussion

The measurement of two rock samples (Coring) utilizing the MICP method in this study resulted in Drainage and Imbibition curves in each rock sample (Fig. 5 and Fig. 6). In Fig. 5 and Fig. 6 for rock sample A1 and rock sample A2, the Water Connate Saturation (Swc) values for sample A1 has Swc value is 5.1022% and samples A2 has Swc value is 7.0813%. Swc of the two rock samples did not have significant value differences. This observation can be attributed to the fact that Swc represents the minimum water saturation retained in immovable rocks. During the process of deposition of rocks, rocks are filled with water with water saturation reaching 100%, but due to the migration of oil and gas that pushes water to move from its position, the water saturation within the rock decreases to values ranging from 20% to 30% [11].

The displacement pressure (Pd) under Drainage conditions for the two curves (see Fig. 5 and 6) was

10.4871 psi (0.7617 MPa) for the A1 rock sample and 516.6259 psi (3.562 MPa) for the A2 rock sample. Analysis of Pd values indicates that the mercury fluid began to intrude into the rock samples, with the A1 rock sample demonstrating greater effectiveness. This observation suggests that a lower Pd value is advantageous, as it implies a higher degree of connectivity among the pores within the rock [10], [14], thereby enhancing the fluid flow capacity in the rock [4].

The Drainage condition curves presented in Fig. 5 and Fig. 6 have been combined to illustrate the trend of the Drainage condition curve which reflects the quality of the permeability possessed by the two samples, as depicted in Fig. 7.

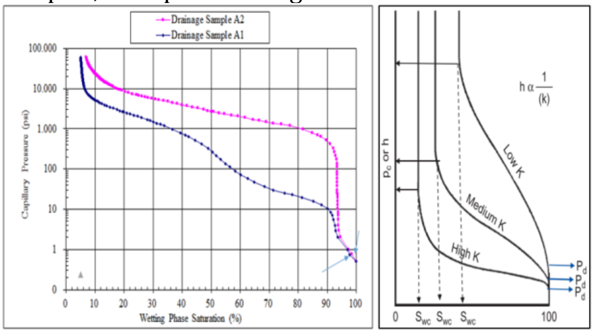

Fig. 7: Drainage Variation Curve of Capillary Pressure Curve to Wetting Phase Saturation in sample A1 and A2.

Evaluating the trend of the Drainage curve in Fig. 6 which corresponds to Fig. 3, it is found that the A1 rock sample has a medium permeability quality and the A2 rock sample has a low permeability quality. This is in accordance with the basic data in Table 1 obtained from the SCAL analysis. This shows that the smaller the capillary pressure, the smaller the Pd, the better the connectivity between the pores in the rock, the better the permeability value of the rock [2]. Specifically, lower displacement pressure (Pd) values, like those found in sample A1, indicate that rocks with well-connected pore spaces can better support hydrocarbon flow. This knowledge can identify reservoir formations with higher potential for efficient fluid extraction.

The findings presented herein provide empirical support for the implementation of more targeted recovery methods on a technical level. In geological formations characterized by lower permeability, exemplified by sample A2, it may be essential to employ techniques that utilize higher injection pressures or alternative recovery methodologies to optimize fluid recovery. By leveraging capillary pressure data, reservoir managers can formulate recovery strategies that are not only cost-effective but also specifically tailored to the unique structural attributes of each reservoir.

This study highlights the significance of utilizing high-pressure instruments, such as the Autopore V 9600, for accurate MICP measurements, especially when working with rock samples exhibiting lower permeability. The employment of such advanced equipment improves data quality, thereby assisting managers in the selection of the most suitable technologies and methodologies for effective long-term reservoir management. Collectively, these findings offer a practical framework for the formulation of more accurate and efficient strategies for oil recovery.

4. Conclusions

Capillary pressure using the MICP method, which involves the injection of mercury fluid at the lowest to highest capillary pressure of 60,000 psi in the two rock samples in this study, affects the permeability level of a rock. Low Capillary Pressure in the rock indicates the higher permeability level of the rock to drain the fluid so that it can drive the Wetting Phase fluid (water) into the Non-Wetting Phase fluid (oil). This can be shown from the value of Displacement Pressure (Pd) or Capillary Entry Pressure in the Drainage condition of the two rock samples from two different wells but still in the same Central Sumatra basin. Specifically, the displacement pressure (Pd) under Drainage conditions was shown at 10.4871 psi (0.7617 MPa) for the A1 rock sample, while the second sample exhibited a displacement pressure of 516.6259 psi (3.562 MPa).

From the Pd values of the two samples, it was determined that mercury fluid intrusion into the rock samples commenced, with the A1 rock sample demonstrating a more pronounced effect. This observation indicates that a lower Pd value correlates with enhanced connectivity of the pores within the rock. The analysis of combining the drainage curves for the A1 and A2 rock samples yielded insights into their permeability characteristics, revealing that the A1 rock sample exhibited medium permeability, whereas the A2 rock sample had low permeability. Furthermore, the capillary pressure was found to correspond with the size of the porosity. This relationship is supported by the basic data obtained from Special Core Analysis (SCAL). The results from the MICP method indicate that as capillary pressure increases, both permeability and porosity decrease.

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