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Klinkenberg-corrected gas permeability correlation for Shuaiba carbonate formation

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ABSTRACT

Standard industry practice to correct absolute gas permeability for what is known as the Klinkenberg effect is to perform single point gas permeability measurement and use assumptions or existing correlations. Available correlations for Klinkenberg-correction of gas permeability are based on measurements of sandstone samples. However, correlations developed for specific fields/formations may not be applicable for other reservoirs of different lithology due to the difference in the pore geometry.

The present experimental investigation was conducted for the purpose of establishing one or several correlations for correcting single point gas permeability measurements (standard conventional core analysis) for the Klinkenberg effect for the Shuaiba Formation (carbonate) as well as to learn whether there is any significant difference between the sandstone-based correlation and the new results for the Shuaiba limestones.

Measurements were made on 175 core-plug samples from the Shuaiba Formation. This limestone unit (Shuaiba) was chosen for study as it is an important oil reservoir in Oman and in the Middle East. Multi-point gas permeability (K_g) was measured for each sample at four different mean pressures and extrapolated to infinite pressure to obtain the Klinkenberg-corrected gas permeability (K_L). Correlation between K_L and K_g was then established.

The robustness of the derived correlation has been validated using existing data (95 additional samples) from another study conducted in parallel to this study on core samples from similar formation (Shuaiba). The results can be useful for directly applying Klinkenberg-correction to other gas permeability data measured at only a single pressure.

1. Introduction

Gas slippage phenomenon (i.e., tendency of gas molecules to slip on the surfaces of porous media) occurs when gas permeability is measured in the laboratory at low pressure. The observed permeability values when gas is used are larger than the true absolute liquid permeability.

The slip phenomena theory was introduced by Kundt and Warburg and was expanded by Klinkenberg (1941) to flow of gas in porous media. A correlation was proposed to correct for the slippage effect. Subsequent studies proposed different correlations. These correlations are reservoir/field specific and are dependent on lithofacies and rock type (Heid et al., 1950; Jones and Owens, 1980; Sampath and Keighin, 1982; Florence, 2007; Tanikawa and Shimamoto, 2009; Civan, 2009).

The conventional method followed in the petroleum industry to estimate Klinkenberg-corrected gas permeability, uses the so-called North Sea equations (Heid et al., 1950; API RP 2, 1956; API RP 40, 1998).

The North Sea equations were derived based on experimental study on a large number (> 1000) of sandstone samples. The correlations developed for sandstones may not be applicable to carbonate rocks, however, because pore systems in carbonates are commonly more complex than in sandstones. In general, (siliciclastic) sandstones will have a more uniform porosity distribution and geometry at small scale (i.e., within the same facies) as there are hardly any animal skeletons involved. Sandstone deposition is purely mechanical, while carbonate deposition is partly biological as well. Also carbonates are much more reactive to fluids that move through them (diagenesis) and can cement/dissolve strongly even at shallow depths.

Apart from the North Sea equations for sandstones, to the authors' knowledge, there is no dedicated study for establishing a correlation for carbonates. Therefore, the present study aims to

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Nomenclature

A	Cross sectional area, cm^3
K_g	Gas permeability, mD
K_L	Klinkenberg-corrected gas permeability, mD
L	Length, cm
ΔP	Differential pressure, mbar
Q	Volumetric flow rate (cm^3/min)
N.S.E.	North Sea equations

establish a correlation for correcting single point gas permeability measurements for the Klinkenberg effect for the Shuaiba Formation (carbonate) and examines the degree to which the new correlation determined for carbonates of the Shuaiba Formation differs from the North Sea equation.

1.1. *Shuaiba geological setting*

The Cretaceous carbonate platform of Oman shows a complex internal architecture, rather than a "layer-cake" configuration. For example, Habshan Formation of Lower Cretaceous shows large-scale Arabian Plate margin configuration (large clinoforms of approximately 300 m thickness), whereas the Shuaiba and Natih formations show different-scale intra-shelf basins. Smaller-scale clinoform complexes are associated with the margins of these intra-shelf basins. These intra-shelf basins are often filled with argillaceous lime mudstones interbedded with deeper-water shales and redeposited grainstones and packstones. An example of these intra-shelf facies is the upper Shuaiba, which is restricted to the Bab intra-shelf basin (located in northwestern Oman and the United Arab Emirates), where it was deposited following a relative drop in sea level of several tens of meters, spanning the early to late Aptian boundary (van Buchem et al., 2002).

The Shuaiba Formation is the uppermost unit of the Kahmah Group and consists of an Aptian carbonate complex of some 100 m thick (Forbes et al., 2010). It comprises the Lower Shuaiba Formation (including reservoir units LSh1, LSh2, LSh3) and the Upper Shuaiba Formation (including reservoir units USh1, USh2, USh3). The depositional patterns in the Shuaiba Formation are highly complex, and include open marine areas, shallow marine (rudist-rich) shoals and lagoonal (semi-restricted) environments (Amthor et al., 2010) (Fig. 1). Moreover, there is a variance between the Lower and the Upper Shuaiba, the Lower Shuaiba consists of laterally extensive algal (Bacinella/Lithocodium) skeletal wackestones to boundstones. These are overlain by more chalky carbonates, which can be enriched in organic matter, in some areas reaching source rock quality. The upper part of the Shuaiba is more variable and contains cleaner foraminiferal and sometimes rudistrich, wacke-packstones and occasionally rudstones. The upper part of the Shuaiba consists of interbedded calcareous clays and limestones. The clays have a variable composition ranging from smectite/illite to kaolinite/chlorite dominated.

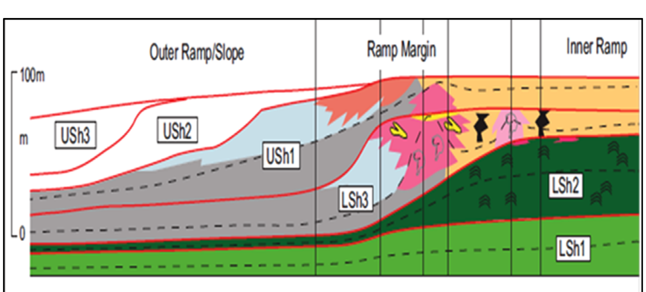

Fig. 1. Depositional environments and reservoir units of the Shuaiba Formation (after Forbes et al. (2010)).

Consequent to all of the above; reservoir characteristics, including distributions of porosity and permeability, are reflecting the particular assemblage of depositional environments. Permeability values for Shuaiba Formation range from 0.1 mD to several 1000s of mD.

2. Methodology

2.1. *Core selection and preparation*

In this study, core samples were selected randomly from a number of Shuaiba fields and wells as shown in table below. 58% of the samples were from the lower units while the rest (42%) were from the upper unit.

The present study measured 175 1.5-inch-diameter (from which 158 samples were used for the derivation of the correlation while rest were used as part of sensitivity measurements), horizontally-oriented core-plug samples from various fields representing Shuaiba Formation (Upper and Lower Shuaiba). Core selection was based on visual inspection of a large number of core samples.

Samples were selected with care to avoid heterogeneities, such as fractures and large vugs. The samples were cleaned, and dried in an oven at 90 °C for a few days to remove any residual fluids that might alter the experimental results. During drying, random samples (around 10) were weighed at 12-h intervals until weights remained constant, indicating that the samples were completely dry. The samples were then cooled to room temperature in desiccators prior to conducting measurements.

2.2. *Porosity measurements*

Porosity for all the selected samples was evaluated by direct measurements of both grain and bulk volumes. Grain volume was measured using a digital helium porosimeter and bulk volume was measured by both caliper (dimensioned measurement) and mercury immersion methods.

2.3. *Permeability measurements*

A digital gas permeameter was used to measure gas permeability. This device measures the flow rate, differential pressure and back pressure, which are the parameters used in the following equation to compute gas permeability:

$$K_g = \frac{0.0176 * Q * L * 1000}{\Delta P * A * ((\Delta P + 2P_2)/2)} \tag{1}$$

Where K_g is gas permeability (mD), L is length of core plug measured (cm), A is cross sectional area (cm^2), D is sample diameter (cm), Q is gas flow rate (cm^3/min), ΔP is differential pressure (atm) and P_2 is back pressure (atm).

For each of the 175 samples, gas permeability was measured four times at different mean pressures. The gas permeability was then extrapolated to infinite mean pressure to get Klinkenberg-corrected gas permeability.