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Error and impact of porosity-permeability transform in tight reservoir

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ABSTRACT

Porosity permeability transforms are used to evaluate permeability; this is a widely accepted and used method in the petroleum industry. There are number of uncertainties associated with porosity permeability transforms such as for example, biasness in the core selection, core to log depth mismatch, permeability up-scaling and geostatical error. Some of them like depth matching and up-scaling can be eliminated but the uncertainty due to biased core selection and statistical uncertainty remains a challenge even in present times. The effects of those uncertainties are even more pronounced in case of low permeabilities in a tight gas sand reservoir environment. An example for a tight gas sand reservoir field from Middle East was used for this study and it is demonstrated that the general fit to the data significantly underestimates the permeability whereas by using Swanson's mean the predicted permeability is in good agreement with the arithmetic mean of permeability. It was also demonstrated that the way transforms have been obtained has a significant impact on porosity cutoff. It is shown that in tight gas sand reservoir the best way to get porosity permeability transform relationship is by using a non-parametric estimator such as Swanson's mean. An attempt is also made to show the effect of porosity cutoffs on connected hydrocarbon in-place. Further, it has been demonstrated that how porosity cutoff will impact reserve estimation and field development planning.

1. Introduction

Permeability transforms have always been and still are one of the most critical aspect of a model (static/dynamic) building exercise. The direct measurement primarily comes from core data. Until now, no wireline logging tool has been capable of measuring permeability directly. Core analysis provides a varied menu of solutions to the reservoir modelling and if used for reservoir description (Dare, 1982).

It is always a challenge to make modifications to the permeability in static/dynamic modelling exercise. Reservoir engineers and petrophysicist along with geoscientist work hard to resolve this challenging issue (Roadifer and Scheihing, 2011). In most cases this is achieved by making significant global modifications to permeability either at the time of geomodel building exercise itself i.e., in static domain or at the time of history matching i.e., in dynamic domain.

Permeability was first derived in 1856 by Henry Darcy following his experiments on the flow of water through sand, which is also, in a way, the expression of Newton's Second Law (Darcy, 1856). Klinkenberg later obtained permeability differences by using gas or liquid. He found that the difference in the measured permeability values by using a liquid (non-reactive) and gas is fundamentally due to a phenomenon called "slippage of gas molecules" (Klinkenberg, 1941). To apply the slippage correction and get the "correct" permeability it was suggested to extrapolate the apparent permeability to infinite pressure. In a way this represents the property of the rock without any effect of fluid. It was noted that the difference between the liquid permeability and corrected air permeability is significant. Klinkenberg further explained that it is, of course, obvious that if a liquid reacts with some constituent of the core material, e.g., if water causes clay-containing core material to swell, then differences between the permeabilities for different liquids and air can be expected. The same is true if the core material is poorly consolidated so that part of the pores may be plugged off by loose material eroded by the liquid. From a practical point of view, these considerations may be very important; thus, if a problem arises about the water movement in clay-containing formations, the permeability of the formation to dry air might be of no significance or even definitely misleading.

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In present day practice, cores are typically cleaned and dried and then air permeability is usually measured from the derived air permeability; corrections are then applied to obtain the "true" permeability of the rock. In the exercise of permeability measurements porosities are also measured using a non-reactive fluid such as helium (N.R Morrow et al., 1991). The measured porosity helps creating log models to calculate porosity and other properties such as Vshale and saturation. In some cases, these corrected permeabilities have been used to calibrate the permeability measurement from indirect methods such as NMR permeability.

Numerous authors (Jensen et al., 1987; Dvorkin et al., 2009; Suarez-Rivera et al., 2012) have investigated the air and liquid permeability relationships using a wide range of permeability data. For clean sandstone the correlations are found to be very good whereas in shaly sands this becomes very challenging. It is also noted that brine permeability is lower than oil permeability due to the interaction of water with rock surface (Pugh et al., 1991). Discrepancies due to averaging or scale effect between log-derived porosity and core-measured porosity can be accounted for, in various ways (Klein et al., 2007). A direct calibration between well log and core has been established by developing a generic linear relationship between porosity and permeability with standard Archie equation (Haro, 2004).

Delfiner (2007) published a study in which he identified a very basic but significant error in the method through which porosity permeability (poro-perm) transforms are generated. In general, the transforms are obtained using a semi log plot of core derived porosity and permeability measurements and by fitting a linear regression line to the data. This significantly underestimates the permeability and the bias lies in the reverse transformation from logarithmic to arithmetic scale. Delfiner (2007) gave a number of solutions so that the arithmetic mean can be preserved in the regression and the error is minimized.

Delfiner (2007) further suggested the use of quartile method because unlike the mean the quantiles of a random variable are preserved under increasing transformation, such as logarithmic or exponential. For rocks below 1 mD, the need to examine the permeability correlation is even more important due to an increase in uncertainty (Macary, 1999).

Roadifer and Scheihing (2011) have taken the example of a conventional reservoir and suggested that the errors in the porosity permeability transform can propagate throughout the model building and history matching process. This error results in a significant underestimation of hydrocarbon in-place and recovery.

In this study an attempt is made to demonstrate the impact of incorrect estimation of permeability from a transform and its impact on other hydrocarbon in-place and reserve for the case of a tight gas sand reservoir from the Middle East.

2. Porosity permeability transform

Porosity Permeability transforms are often used to predict permeability from core data and further populate it in the reservoir model. Generally, a correlation established at the scale of a few inches core plug is used for a grid size of few square kilometers, which may lead to a highly pessimistic results. In the presence of strong permeability contrasts, the bias between the corrected up-scaled permeability and geometric mean can be quite large; this bias could be even larger in the case of an arithmetic mean.

Direct input of up-scaled porosity into an exponential core-scale permeability transform amounts to forcing geometric permeability averaging (Randolph et al., 1984), which leads to underestimation of true up-scaled permeability in the case of a tight gas sand reservoir where heterogeneity is significant (Holditch, 2006).

Porosity and permeability data samples used in this study are taken from a field in Middle East. These plugs were drilled using simulated formation brine as a drill bit lubricant. Upon receiving the core samples, were cleaned under cool solvents in soxhlet extractors using a mixture of chloroform and methanol. The samples were dried in humidity oven at 60 °C with 60% humidity. They were then allowed to cool to room temperature in a sealed desiccator prior to analysis. Gas permeability was measured using a calibrated steady state permeameter with nitrogen gas as the flowing medium. The flow was allowed to stabilize before the readings were taken. The readings were then corrected for Klinkenberg effect.

Porosity and permeability data samples are plotted in Fig. 1. The regression features a 49% variance of log of permeability, which in a way corresponds to a correlation coefficient of 0.70. This is considered to be a reasonable fit considering the amount of heterogeneity in the samples and other errors such as core cleaning and drying, selection bias, etc.

The solution is an exponential trend line as shown in equation (1):

$$K = 0.0003 * \exp(0.7127 * \phi) \tag{1}$$

However, when one tries to estimate the value of permeability using this equation for a particular porosity range, it significantly underestimates the average permeability with a factor of ~3.5when compared to the arithmetic mean of permeability as shown in Table 1.

When the data used in the study was analyzed, the arithmetic mean of the permeability data was 2.224 mD, whereas, using the general fit of the regression shown in Fig. 1 the predicted mean permeability was 0.675 mD, which is significantly lower than the arithmetic mean.

This demonstrates that the underestimation is much more severe in the case of a tight gas sand reservoir. In comparison, for a conventional reservoir, the permeability difference is underestimated by factor of 2 as described by Delfiner (Delfiner, 2007).

This can be explained by Jensen's inequality (Jensen, 1906), which shows that the mean of the exponential of a random variable is always greater than the exponential of the mean. The bias appears because of the application of a nonlinear transform, which is not the same as taking the mean.

To solve this problem of underestimation, methods such as quantiles have been used whereby the quantiles of a random variable are preserved under increasing transformation such as

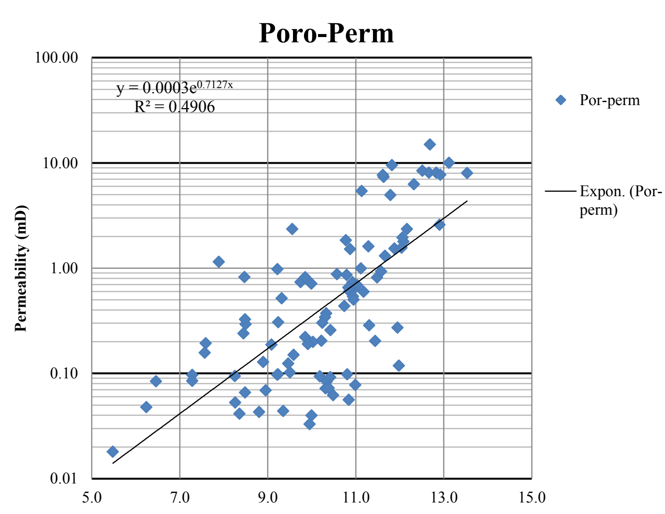

Fig. 1. Poro-perm transform using a general fit.