# Calibration of digital pore scale models

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## ABSTRACT

Digital rock analyses (DRA) has advanced to a level that makes it a very valuable supplement to traditional SCAL. Currently the main challenges are related to handling samples with a large fraction of micro-porosity, with heterogeneities on several scales, and to assign wetting properties correctly. In this paper, we describe how models generated using DRA are calibrated against robust petrophysical and geological data in order to verify digitally derived reservoir properties. Once the verified pore scale data is established the models can be applied to analyses of many different scenarios.

The first step of verification of the digital representation is comparison with experimentally derived porosity and absolute permeability data. The absolute permeability is mainly governed by the larger pore throats of the pore space, and therefore less sensitive to image resolution. The total porosity can be correctly calculated by including micro-porosity, which in this context means pores smaller than the resolution of the discretized image-acquisitions. Hence a multi-scale imaging approach is required to capture the continuous distribution of pore-sizes of a given rock sample.

The digital representation of the pore space is compared to mercury injection capillary pressure data for quality control and verification. In some cases several digital models, representing different parts of the samples must be combined to achieve a representative model.

In order to calculate realistic multiphase flow properties, information of the wetting characteristics is essential. For example, both the fraction and distribution of oil wet surfaces and contact angles are subject to changes. Advanced imaging techniques for spatial mapping of fluids in combination with laboratory data can be used to narrow the possible range of these parameters.

## INTRODUCTION

Digital rock analysis (DRA) is a technology under constant development, and several studies have indicated that DRA offers significant value for delivering fast-track special core analysis

(SCAL) data [1-5]. The additional aspect is enabling sensitivity studies, such as wettability settings and modelling of relative permeability and capillary pressure in transition zone. An integrated multi-scale imaging and modeling method for determining petrophysical and multiphase flow properties of carbonate reservoir rocks is extensively presented by Kalam et al. [3][4]. The present work show calibration and validation steps using routine core analysis (RCA) data during multi-scale imaging and modeling of sandstone reservoir rocks containing significant content of pores below the image resolution.

One of the key challenges of digital rock analysis is capturing the whole range of pore sizes within one pore scale model. Capturing a representative elementary volume (REV) of a reservoir rock is essential to predict rock properties. The represented volume in a discretized 3D model is the result of the number of grid cells and the size of each grid cell. Higher resolution models will require increased number of grid cells to maintain the REV. A multi-scale imaging and modeling approach will allow for a range of representative volumes, hence a range of resolutions according to the rock complexity. Integration of multiple 3D models, each model representing a finite range of the pore size distribution, allows for characterization of the complete pore system. Micro-porosity, in DRA often referred to as partial volume porosity, is affected by the resolution during image acquisition.

## RESOLUTION IN DRA

Imaging of reservoir rock samples is performed at a range of scales and resolutions, as illustrated in **Figure 1**. The largest scale corresponds to the whole core scale, and image resolution is normally in the range of 200µm per voxel. Images at this scale are used for identification and distribution of lithofacies, and for selection of depths for core plugs. The standard core plug scale, 1.5 inch diameter, is normally scanned at a resolution of 20µm per voxel. These images are used for investigation and spatial mapping of heterogeneities on the core plug scale, which is valuable for extracting representative micro-plugs for pore scale analysis. The micro-plugs are normally in the range of 1-6 mm in diameter, depending on the feature sizes and the required REV within the rock sample. Conventional X-ray computed micro-tomographs (MCT) can image rock samples with a resolution of approximately 1µm per voxel and upwards. Acquisition of pore size information below this resolution will require other sources of imaging. Scanning electron microscopes (SEM) are widely used for reservoir rock analysis, and is especially valuable with the possibility to register high resolution 2D images into the 3D volume generated from MCT. The 2D images could be BSEM images for improved segmentation or QEM-scan data for supporting mineralogical analyses. Investigation of pores down to the nano-scale will require additional imaging techniques, such as FIB-SEM imaging.

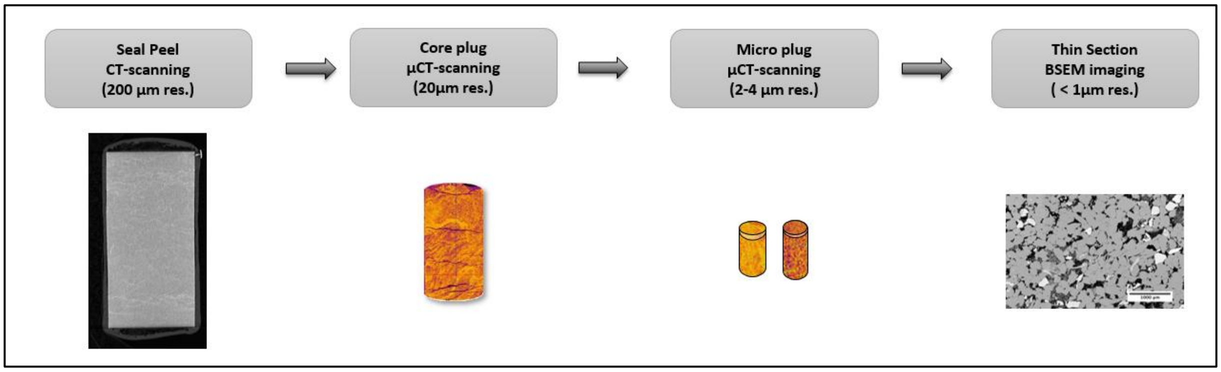


**Figure 1 Scales and resolutions in DRA. Decreasing sample size and increasing image resolution towards right, from the cm scale to the sub-micrometer scale.**

## CALIBRATION USING POROSITY AND PERMEABILITY

Porosity and permeability are chosen as the first calibration points for digital rock analysis. Digitally derived porosity has been a subject for discussion due to partial volume effects from pores smaller than the model resolution. Imaging techniques, such as dry/wet imaging together with registration [6], are being continuously developed and improved to reduce the uncertainties related to quantification of pores. Generation of micro-porosity maps is also used for spatial mapping of various micro-porosity classes within a rock sample. This information is of high importance for selection of relevant locations for higher resolution images, such as SEM or FIB-SEM.

The permeability of a rock sample is mainly governed by the connected network of larger pores. This way the absolute permeability is less sensitive to model resolution compared to other parameters, as long as the main flow paths are well characterized. For rock samples where the main flow paths contain pore throats that require multi-scale imaging, the calibration to experimental data would be of increased importance to validate the integration methodology.

A 5mm diameter mini-plug (sample B), cored from a rock sample from the Norwegian continental shelf (NCS), was scanned in MCT with resolution of 3µm/voxel. The 3D volume was later segmented into three phases representing resolved pores, a micro-porous phase and the solid matrix. Grid based absolute permeability was calculated on the 3D volume, and confirmed in agreement with available routine core analysis (RCA) data. The mini-plug was later saturated with a high-attenuating fluid and scanned again. The 3D volumes were registered on top of each other, and a difference image was generated, to perform a quantitative analysis of the pores below resolution. The total porosity derived digitally is in good agreement with RCA derived data, as shown in **Figure 2**.

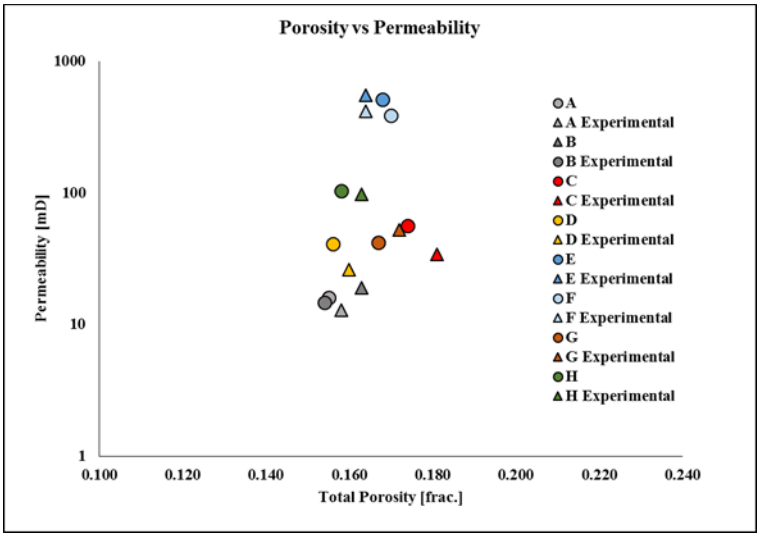


**Figure 2 Comparison of DRA and experimentally derived porosity and permeability data**

## CALIBRATION USING MICP

Mercury injection capillary pressure (MICP) data is a fast and cost efficient method to acquire information regarding the pore throat size distribution. The spatial distribution of the derived sizes are although unknown. Comparison of experimental MICP data with the digital models will confirm whether the pore size distribution derived from multi-scale digital models is captured.

Any comparison or calibration between DRA and experimentally derived data should also be performed at the same scale to capture local heterogeneities. Routine core analysis on core plugs is therefore only a subject of comparison to DRA data where the effective properties are calculated according to the identical core plug scale.

Capillary pressure curves are simulated on the pore network from sample B. There is good agreement with experimental MICP for the entry pressure and at high water saturations, **Figure 3**, hence for the well characterized pore throats above imaged resolution. The maximum capillary pressure reached during network simulations is defined by the smallest pore throats resolved in the system, which corresponds to the network resolution.

Primary drainage simulations on the segmented mini-plug 3D volume resulted in a simulated initial water saturation of approximately 50% after oil/water primary drainage displacement, **Figure 3**. The maximum capillary pressure reached during network simulations was 0.6bar.The capillary pressure curve for DRA in the figure is extrapolated to 5bar illustrating the difference of saturation at increased capillary pressures. It is however the curve shape covering the complete saturation range which is the main calibration point.

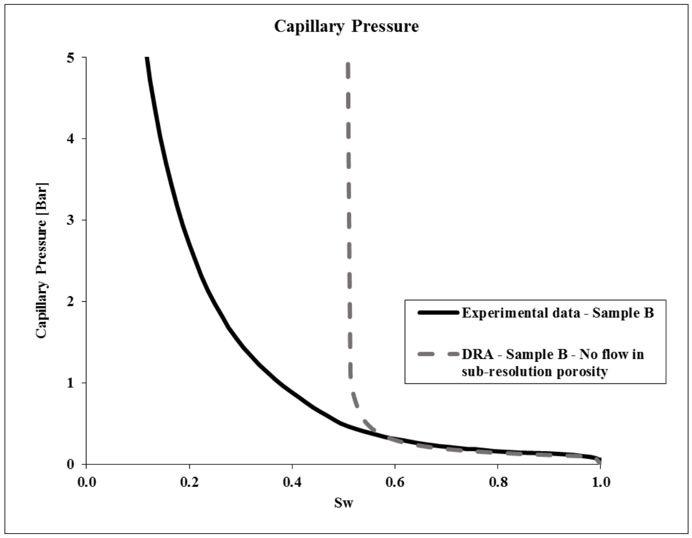


**Figure 3 Comparison of capillary pressure curves from single scale model against capillary pressure curve derived from experimental MICP**

The equivalent brine saturation derived from experimental MICP, at oil/water capillary pressure at 5bar, is approximately 12%, meaning a significant part of the occupied pore volume is related to pores below original image resolution and isolation of resolved pores in connection with the micro-porous phase. Imaging at higher resolution is necessary to resolve and characterize these pores, and the connecting pore throats, in order to predict petrophysical properties and the flow behavior in the reservoir.

## PROCESS BASED MODELS REPRESENTING PORES BELOW INITIAL SCAN RESOLUTION

The micro-porous phase in the initial 3D volume is assigned a uniform fraction of micro-porosity which initially is not directly applicable for fluid flow, but contributing to water saturation as clay-bound water. The resolution used for acquisition of the MCT volume, 2.5µm/voxel, will capture the volume fraction of porosity within the micro-porous phase, but will not capture the pore sizes or the connectivity within this phase. High resolution imaging is used for characterization and modelling of these pore sizes, which allows for integration of pore sizes below the initial scan resolution. In addition, the initially impermeable micro-porous phase will also disconnect resolved pores in the MCT volume, which is an additional contributor to immobile water saturation. The experimental MICP data is investigated for the pores below imaged resolution, **Figure 4**, with focus on the range of pore throat sizes from the smallest pores represented in the 3D model to the pore throats representing the defined capillary pressure of 5bar. This capillary pressure represents the pore throat sizes excluded from the original 3D model due to resolution, which is now the target capillary pressure curve for the process based models. By normalizing the saturation axis according to the range of saturation for the sub-resolution pore throat sizes, the re-plotted curve can be used as a one-to-one calibration curve for the modeled representation of the micro-porous phase. This multi-scale analysis is an attempt to capture the continuous pore size distribution in reservoir rocks by using multiple imaging techniques for a range of resolutions.

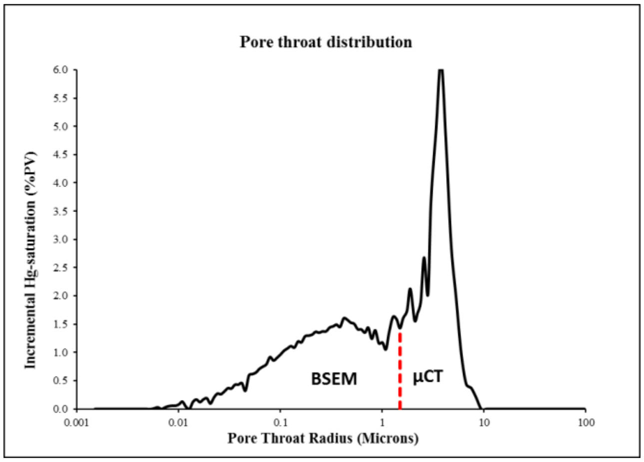


**Figure 4 Pore throat size distribution derived from mercury injection data (MICP). Dashed line indicates boundary between MCT and BSEM for representation of resolved porosity.**

The 3D models are generated using the process based modeling approach [7]. Input parameters such as particle size distribution, porosity and mineralogical composition for the modeling part are gathered from high resolution backscatter scanning electron images (BSEM). Generic models representing aggregates of kaolinite clay, such as the examples shown in **Figure 5**, is modeled with the basis of one model-object representing each kaolinite booklet. The inter-booklet porosity is used as target porosity and the intra-booklet porosity is added as immobile water saturation. Modeling and calculations of petrophysical properties are extensively described by Øren et al. [8-9], and are not detailed in this paper.

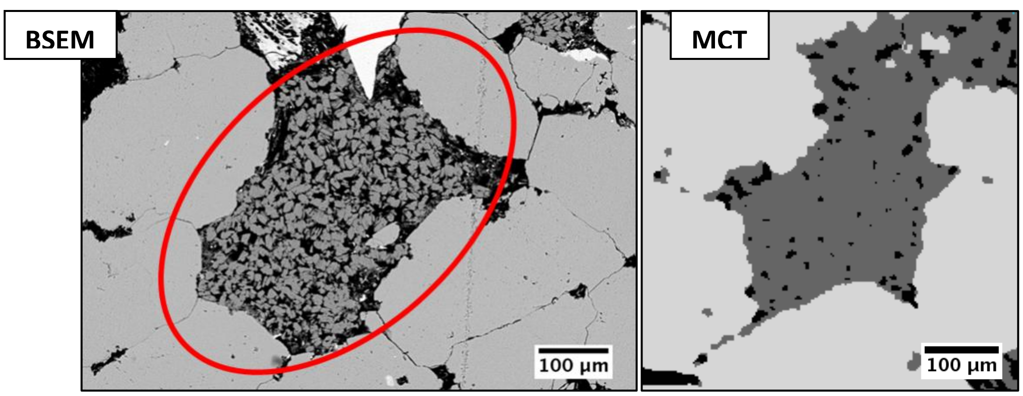


**Figure 5 Left: BSEM image of a pore containing an aggregate of kaolinite clay booklets. Right: Segmented MCT slice image, acquired with coarser resolution, of a pore containing pore filling clay and isolated pores.**

A wide range of kaolinite aggregates are analyzed and modeled to define a porosity and permeability trend representing the observed variations within the kaolinite filled pores. Pore networks are extracted from the various generic models and flow simulations are performed.

Networks extracted from high resolution MCT and FIB-SEM images of kaolinite aggregates are used as validation of the process based modeling. The simulated J-functions from the process based models and CT-images, as shown in **Figure 6**, are showing similar shape, and calculated statistical functions of both particles and pores from BSEM images and generated models show similar size distributions.

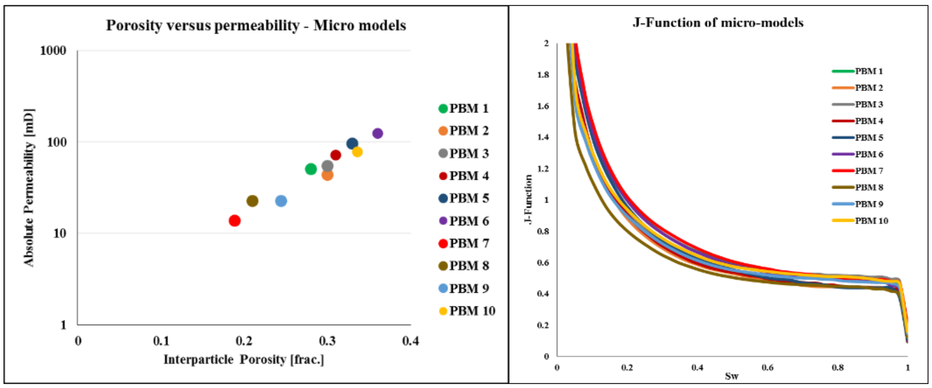


**Figure 6 Left plot showing inter-particle porosity and permeability data for process based models of kaolinite clay aggregates. Right plot showing simulated J-Function data for a range of process based models representing pores related to kaolinite clay aggregates**

The integration of pore networks from models of multiple scales to predict flow behavior in reservoir rocks has been published earlier by Kalam et al.[3][4], and is only described briefly in this article. The current methodology is conceptually identical to the steady state upscaling method, where each defined rock type is represented by an input file containing the corresponding effective properties. The following properties are assigned to each grid cell; porosity, absolute permeability tensor (*kxx*, *kyy*, *kzz*), capillary pressure curve and relative permeability curves. The generated micro-porosity map is used to maintain the spatial distribution of the representative rock types within the micro-porous phase.

Single phase up-scaling is done by assuming steady state linear flow across the model. The single phase pressure equations are set up assuming material balance and Darcy's law:

$$\nabla \bullet (k\nabla P) = 0 \text{ with boundary conditions}$$
$$p = P_0 \text{ at } x = 0, p = P_1 \text{ at } x = L$$
$$v \bullet n = 0 \text{ at other faces}$$

The pressure equation is solved using a finite difference formulation. From the solution one can calculate the average velocity and the effective permeability using Darcy's law. By performing the calculations in the three orthogonal directions, we can compute the effective or up-scaled permeability tensor for the core sample.

Effective two-phase properties (i.e. capillary pressure and relative permeability) are calculated using two-phase steady state up-scaling methods. We assume that the fluids inside the sample have come to capillary equilibrium. This is a reasonable assumptions for small samples (<30cm) when the flow rate is slow (<1m/day).

The percolating macro pore space, from the segmented scan of the mini-plug, is the main rock type for the integration step. The number of rock types representing the micro-porous phase is depending on the ratio between the smallest pores represented in the macro pore space and the pore size representing the maximum defined capillary pressure for the simulations, and the classification of rock types are based on porosity maps from MCT and analyses of BSEM images. The properties of the rock types representing the micro-porous phase are integrated according to the trends, as seen in **Figure 6**, derived from the process based modeling, and the spatial distribution is governed by the porosity maps derived from MCT.

DRA performed on sample B, with integrated micro-models for representation of the micro-porous phase, shows a very good agreement with experimental data, as seen in **Figure 7**. The resulting $S_{wi}$ after simulated primary drainage is 14% compared with the experimental value of 12%.

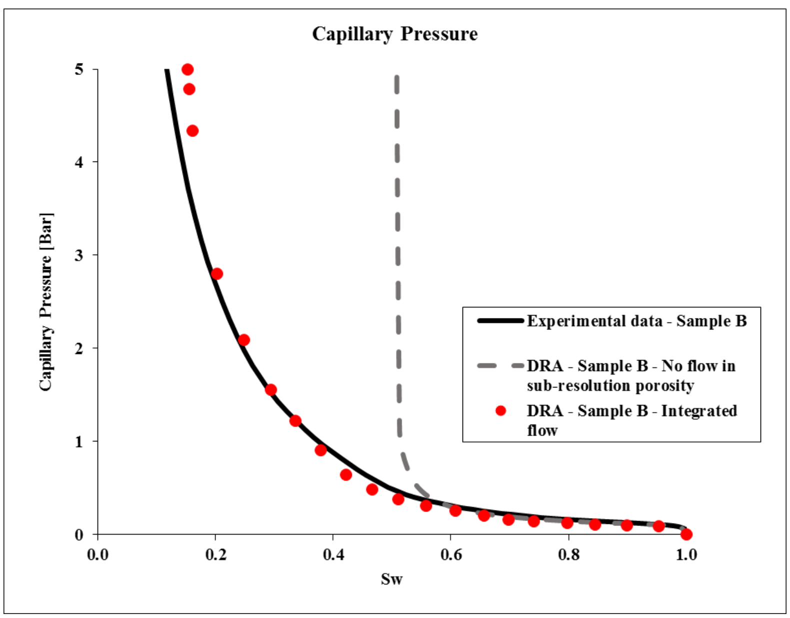


**Figure 7 Comparison of capillary pressure curves derived from experimental MICP, DRA with no flow in sub resolution porosity and upscaled DRA with integrated micro-models representing sub-resolution porosity**

Spatial mapping of saturations using imaging techniques has been presented earlier by Knackstedt et al.[10], and is a valuable tool for validation of digitally derived end-points after various displacement processes. The volumetric fraction of residual saturations is one calibration point. The additional calibration point of the spatial distribution is equally important for validation of digital rock analysis. The spatial distribution of trapped fluids observed in MCT based studies are used to calibrate wettability parameters used in digital flow simulations to replicate physical experiments. Validation of digital simulations opens up for anchoring of existing experimental data, such as SCAL data, prior to sensitivity studies with increased confidence.

Simulation of multiphase flow behavior in a reservoir rock is dependent on implementation of correct wetting characteristics, such as the fraction and distribution of oil-wet surfaces and contact angles. The combination of DRA and SCAL data, such as imbibition capillary pressure curves, can both provide additional information and reduce uncertainties during reservoir characterization. Anchoring of forced imbibition capillary pressure curves may also increase certainties regarding data points at zero capillary pressure as well as the capillary pressure curve representing the spontaneous imbibition. The relationship between contact angles and curve shape of imbibition capillary pressure can also be investigated using DRA.

One aspect is the calibration of wettability parameters for DRA simulations, while the other aspect is the validation and extension of experimentally derived data by DRA. Calibrated models from DRA can furthermore be used for sensitivity studies like variations in initial water saturation or simulations representing different wettability scenarios in the reservoir column.

## CONCLUSIONS

Several studies have indicated that DRA, in combination with routine core analysis, offers significant value for delivering fast-track special core analysis data, including characterization of the micro-structure of the rock, as well as static and dynamic reservoir properties. To be able to capture all pore sizes contributing to the different properties a multiple scale imaging workflow is developed. Calibration of the generated 3D models is done by using RCA data such as porosity, absolute permeability and mercury injection capillary pressure data. It is important to emphasize that all comparisons between digital and experimental results should be performed at identical scales.

To get data early is important for the oil and gas industry in order to compile reliable reservoir development plans as early as possible. After more advanced experiments, in example wettability analysis from SCAL studies, the capillary pressure and relative permeability curves can be revisited, calibrated and anchored. Calibrated digital models decreases the uncertainties related to sensitivity studies such as variations of initial water saturation and variations in wettability characteristics. The combination of advanced routine core analysis and DRA can provide reliable and well calibrated data for reservoir characterization.

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