Predicting Laboratory Scale Permeability on Berea Sandstone Thin Section using 3D Porous Media Reconstruction and Upscaling Method

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Abstract—**Present paper describes a new approach to predict laboratory scale permeability using information of thin section image. The workflow was applied on Berea sandstone thin section which has similar length as the measured core plug. In this workflow, instead of using a part of thin section, full thin section image was used as an input to predict permeability at laboratory scale. The workflow is using 3D porous media reconstruction method to estimate permeability at pore scale level. To define heterogeneities at laboratory scale on full thin section image, grain size vertical profile was calculated. Building blocks were determined based on grain size vertical profile trends. Upscaling from pore to core plug scale was applied on full thin section image of Berea sandstone. Permeability at laboratory scale was calculated and the results match well with accuracy ~85 compare to laboratory data.**

Index Terms— **Pore Scale Permeability, 3D Porous Media Reconstruction, Fluid Flow Simulation, Grain Size Vertical Profiles, Upscaling Permeability.**

I. Introduction

Thin Section is easy to obtain and readily available data from oil field. Thin section can be created from core plugs or from unconsolidated samples, such as cuttings, chips and sidewall core plugs, which cannot be experimentally measured. The general purposes of creating thin section are usually for geological evaluation and mineralogy sorting purposes and it's rarely used to estimate physical properties.

There are several studies working on predicting permeability from thin section image. Berryman [1] used Kozeny-Carman relation approach and suggested a relationship for estimating the specific surface area from spatial correlation functions of thin section images. However, the changes of resolution give large errors on predicting permeability. Some of parameters also need to obtain from measurement and cannot be directly used from thin section image information [2].

Other researchers simulate physical properties on 3D porous media generated from thin section (2D image) to predict permeability. Adler et.al [3] used unconditional truncated Gaussian method to generate 3D image of pore structure. Okabe and Blunt [4] used more sophisticated statistical techniques, Multiple Point Statistics (MPS), to reconstruct 3D porous media of rock. The application of MPS has successfully been used to reconstruct connectivity of sandstone and carbonate samples. However, applying such statistical properties to capture important features of porous media and then generate 3D pore structure still need an excessive amount of computational time.

Keehm et.al [2] showed that porosity and two point correlation functions can still be used to correctly simulate connectivity and permeability in clastic sediment if a sequential indicator simulator (SISIM) is used [5]. This method appears to produce correct connectivity when compared to 3D x-ray tomography. However, since the 3D porous media reconstructed from this method only in mm scale, this methodology sometimes failed to predict anisotropy of permeability at core plug scale [5]. Kameda [6] used the same method and modified the workflow. Combination of 2D to 3D porous media by Keehm and Upscaling method was applied on sandstone thin section. Kameda classified input for reconstruction method into three type: porous, patchy and tight based on the observation on thin section images [6] and showed an improvement on permeability prediction. However, to classify the input into three types of input detail observation of thin section images is needed.

The main purpose of this study is developing a new workflow to predict permeability at laboratory or core plug scale using information from full thin section image. In our assumption, full thin section image has similar scale with core plug. To test this workflow the thin section was cut vertically through core plug. Berea sandstone core plug used to validate the new workflow. Pore scale permeability is calculating on 3D generated porous media using fluid flow simulation. In our work, we modified Keehm's methodology and adding new parameter to improve computational time of 2D to 3D porous media reconstruction and compared with known sample from 3D CT-Scan image.

Once full thin section image is obtained, the grain size vertical profile trends were calculated from image. The building blocks were determined based on the trends showed from grain size vertical profile. The building blocks were used as a benchmark to upscale permeability from pore to core plug scale. The results from this workflow will be compared with data from measurement of Berea sandstone core plug.

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II. Methodology

A. Core Plug and Thin Section of Berea Sandstone

Berea sandstone is one of rock which has been used for many years as a standard material in core analysis research. For this study, the particular Berea sandstone sample has size of 2 inch length and 1 inch diameter. Laboratory data for average of three times measurement showed porosity 17.5 % and Klinkenberg-corrected air permeability 196.3 mD.

Full thin section image is required as an input for the new workflow to predict permeability at laboratory scale. We assume the length of full thin section image has the same length with core plug. To obtain this objective, the thin section was cut vertically through core plug. Fig.1. shows scale comparison between core plug and full length of Berea sandstone thin section.

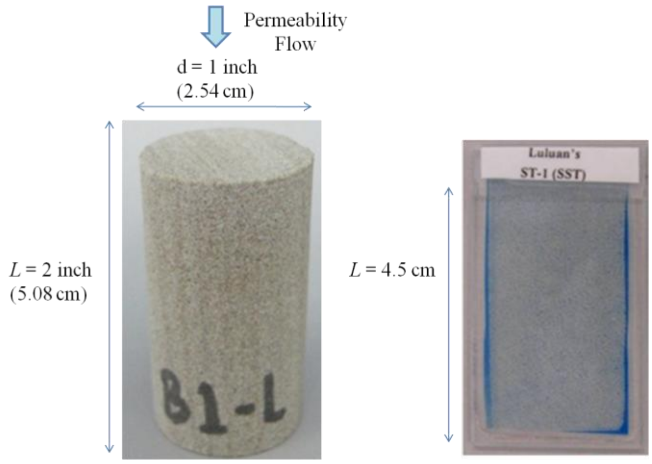

Fig.1. Scale comparison between core plug and full length of Berea sandstone thin section. The length of full thin section image is 4.5 cm.

B. Estimation of Laboratory Scale Permeability using Berea Sandstone Thin Section

To predict laboratory scale permeability, several methods are combined as part of the workflow. The 3D porous media reconstruction method as an input to simulate fluid flow and estimate pore scale permeability, grain size vertical profile to define heterogeneities of full thin section image and upscaling permeability from pore to core plug scale. All processes of the workflow were running on personal computer Intel (R) Xeon CPU 2.67 GHz with 8 GB of RAM. Matlab, SGEMS, Jmicrovision software and LBM fluid flow simulator were used as toolboxes software for this work.

Pore Scale Permeability Estimation

In this part, stochastically reconstructed porous media from Keehm [2] was adopted. It is believed that this method is good enough to reconstruct connectivity of clastic samples [6]. To improve computational time, we modified this method and add another parameter, sample points which is used as conditional data. The additional of new parameter improve computational time to reconstruct 3D porous media by 30 times compare to initial method.

Realizations of 3D porous media were simulated using sequential indicator simulation (SISIM) conditioned to porosity, variogram and new parameter, sample points extracted from training image (TI). The SISIM algorithm was taken from Stanford Geostatistical Modeling Software (SGEMS) by Remy et.al. SGEMS is the next generation of Geostatistical Software Library (GSLIB). The training image was first reformatted from jpeg to sgems format using MATLAB and used as an input on SGEMS software. Fig. 5 shows input parameter to reconstruct 3D porous media from 2D image.

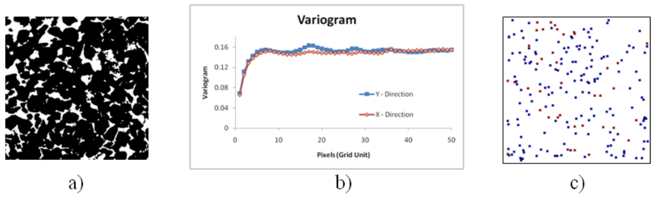

Fig.2. Input Parameters for simulation: Porosity, Variogram and Sample Points extracted from Training Image.

Once the 3D porous media generated, permeability is estimated by conducting numerical flow simulations on the 3D porous media. The reconstructed 3D porous media are geometrically very complex and may contain statistical noise due to the stochastic nature of their construction [2]. The Lattice Boltzmann Method (LBM) for fluid simulation is an appropriate choice for these cases. This method is a robust technique that simulates flow according to simple rules governing local interactions between individual particles and recovers the Navier-Stokes equations at the macroscopic scale [7].

Boltzmann equation solved by counting particle density distribution at time t and location of r. From the local flux, a volume averaged flux can be calculated. Then, the absolute permeability is computed in a manner analogous to a laboratory measurement: a pressure head or body force is directly applied to a digital sample. The resulting fluid flux is computed and permeability is calculated according to the Darcy's law.

$$k = \frac{\langle Q \rangle}{\nabla P} \mu \qquad (1)$$

The flow simulation is performed with pressure gradient (∇P) assigned across opposite faces of the 3D cube. Next, a volume averaged flux $\langle Q \rangle$ is computed from local flux. μ is the dynamic viscosity of the fluid.

Grain Size Vertical Profile of Full Thin Section Image

Grain size vertical profile is used to define the heterogeneity on full thin section image. We define the heterogeneity as the coarse and fine part of the section. This method was first employed by Rubin [8] [9]. The actual grain size cannot estimated with this method but enough for tracking changes in sediment grain size, which in some settings related flow changes. The spatial autocorrelation r between two rectangular regions (plaquettes) in an image is:

$$r = \frac{\sum_i (x_i - \bar{x})(y_i - \bar{y})}{\sqrt{\sum_i (x_i - \bar{x})^2}\sqrt{\sum_i (y_i - \bar{y})^2}} \qquad (2)$$

where x_i and y_i are the intensities of corresponding pixels in two plaquettes, and $\bar{x}$ and $\bar{y}$ are the mean intensities of pixels in the two plaquettes. An autocorrelation curve is determined by calculating r as a function of distance between the two plaquettes. Grain size vertical profile can be implement using autocorrelation curve which computed for each row of pixels in the image.

In this study, this methodology was used to classify the coarse and fine part of section and final result is to define fraction of building blocks for upscaling permeability input. Previous studies [6] shown that rocks contain of coarse grain is more porous than fine grain. Based on this study, we can assume that the coarser part is more porous and the fines part is less porous. The area fraction can be identified by determining the coarse and fine trends of grain size vertical profile.

For image acquisition, magnification 12.5 was used to cover whole area in thin section. The useful of this magnification is it can cover the entire image, with only 9 times taken pictures and cover whole area of thin section. The vertical grain size profile is calculated when full thin section image is acquired. Calculations for grain size vertical profile (autocorrelation curves for ~3000 rows of pixels, smoothed at two scales) took ~1 second on a 2.67 GHz computer.

Upscaling Permeability: Pore to Core Plug Scale

The computed permeability values of small sub-volumes sometimes overestimated or underestimated lab-measured permeability values since the input to compute permeability is in mm scale and measured scale in cm scale [5] [6]. The overestimation is caused by permeability heterogeneity in the relatively large physical measured sample. To overcome these problems, upscaling on the basis of small building blocks can be combined with computed permeability.

The same concept as conventional reservoir upscaling is used in this study. The effective permeability of a 3D network of building blocks (each with a known permeability) may take values between the harmonic and arithmetic average of the block permeability values, depending on their spatial arrangement. The bulk permeability parallel (K_h) and normal (K_v) to bedding are calculated as weighted arithmetic and harmonic averages, respectively, using the corresponding values [10] [11]. The following formulas are the examples of effective permeability formulas for three fractions of building blocks:

$$K_h = \frac{k_a l_a + k_b l_b + k_c l_c}{L} \tag{3}$$

$$K_v = \frac{k_a k_b k_c L}{k_a k_b l_c + k_c k_b l_a + k_c k_a l_b} \tag{4}$$

III. Results and Discussions

This part presents the results and subsequent discussions of the results that obtained in this work. The results would first describe the efficiency of 2D to 3D porous media reconstruction method. The efficiency of this method is shown by comparing fluid flow simulation on reconstructed porous media with 3D CT-Scan image. Tab. 1 below shows briefly the results of three samples of sandstone after the reconstruction method and simulation of fluid flow compare with simulation of fluid flow on original 3D CT-Scan image.

Tab. 1. Comparison of computed permeability between reconstruction method and CT-Scan image.

Sample	Original 3D CT-Scan		Reconstructed 3D Porous Media	
	ϕ (%)	k (mD)	ϕ (%)	k (mD)
Berea	19.6	1360	19.8	1512
Sandstone S(8)	34	13169	35.1	13105
Fontainebleau	14.7	2262	15.1	1550

The computed permeability on reconstructed 3D porous media is in reasonably good agreement with accuracy ~80% - 90% compare to 3D CT-Scan image, which shows implicitly that this method produce good connectivity on sandstone sample. The good accuracy on the reconstructed method compare with CT-Scan data is also caused by considering Representative Elementary Volume (REV) scale on training image selection and the comparison on the same scale size, mm to mm scale size of sample.

With good accuracy compare to experimental method (CT-Scan) and by modifying initial method (Keehm's), the computational time improve until ~30 times and can generate each 3D porous media almost in real time, ~30 seconds on personal computer. This method is precise and efficient to estimate pore scale permeability on sandstone samples.

Next step is to acquire full thin section image. Full thin section image was captured using microscope. The magnification of 12.5 was selected. This magnification is appropriate to cover all area of thin section with good resolution and minimum number of collecting images. Through this magnification, full thin section image at cm scale can be covered with nine times images collection. These images were collected and stitched together into one image. Fig.3. shows the workflow and process of image collection and stitching to create full thin section image.

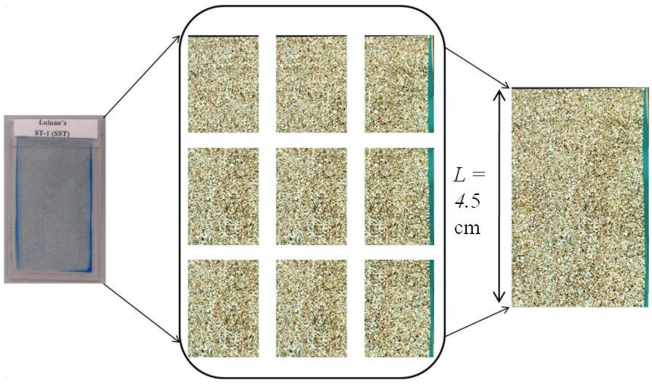

Fig.3. Image acquisition and stitching processes on full thin section image of Berea sandstone. The length of full thin section image is 4.5 cm.

Once full thin section image is acquired, the next step is calculating grain size vertical profile trends from full thin section image normal to the length of the thin section. First reason of calculating on this direction is because the permeability flow (K_n) was measured on this direction. Second, we assume that low variation is occurred on the lateral side of thin section respective to the permeability flow. The grain size vertical profile was applied on full thin section image and calculated using MATLAB.

The pink trends show the statistical of each row which calculated from each pixel. The results were noisy because the statistics of each row are calculated for small samples. Noise on pink trends was reduced by smoothing and averaging successive rows. The results show on the blue trends which show the smooth line. Calculations for this vertical grain size profile took less than 1 second on 2.67 GHz personal computer.

The smoothing (blue) trends on full thin section image of Berea sandstone show the coarsening and fining part of the image. Based on the trends, there are three areas where the trends are bending. The right bending indicated that the area represents coarse area. Based on literature [8], coarse grain area is more porous and fine grain area is less porous than coarse grain.

From the observation on the trends, we can conclude that area *a*, is the coarsest area, *b* is coarser than *c*, and *c* is the finest area. Building blocks for upscaling were created based on the classification of these areas and assume that low variation is occurred on the lateral side of thin section. The length of each area is shown on yellow arrow respective to *a*, *b* and *c*. The length of each area was used as a fraction for upscaling method input.

Three images were selected which represent the *a* area or porous (coarse grain), *b* area or patchy and *c* area or tight (fine grain). With assumption of low variation is occurred on the lateral side of thin section, the selection of each image on each block can be justified. The 2D to 3D porous media reconstruction and fluid flow simulation was applied to estimate permeability at pore scale from each image. Fig.4. shows building blocks and application of upscaling permeability workflow on full thin section image of Berea sandstone.

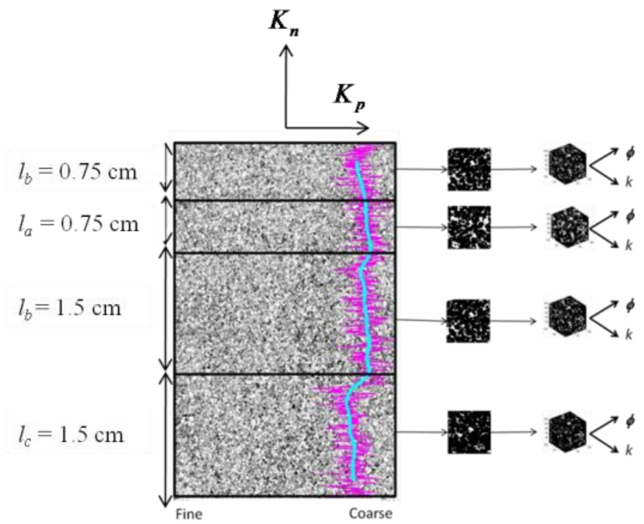

Fig.4. Building blocks for upscaling permeability workflow on full thin section image of Berea Sandstone.

Based on grain size vertical profile, the length fraction of porous area (l_a) is 0.75 cm, the length fraction of patchy areas (l_{b1}) is 0.75 cm and (l_{b2}) 1.5 cm and the length fraction of tight area is 1.5 cm. length fraction of patchy area and l_c is length fraction of tight area.

Three images which represent the porous area, patchy area and tight area were collected. These images were used as an input to estimate permeability from each building block using 2D to 3D porous media reconstruction and fluid flow simulation. The workflow followed the steps on simulation study. Porosity was calculated using arithmetic average from three images. The value is 15.1 % compare to 17.5 % from laboratory measurement. Permeability estimation using upscaling permeability workflow is 166.5 mD which estimated on normal to permeability flow (K_n) and 382.8 mD, parallel to permeability flow (K_p).

Fig.5. shows the plotted of permeability comparison. Blue dots show pore scale permeability estimation on each representative image of building blocks. Red line is permeability measured from core plug and green line is permeability from full thin section image by applying upscaling permeability workflow. Red line value is equal to one since it equals to 100% similarity with measurement value. Green line and blue dots is compared respective to measurement value.

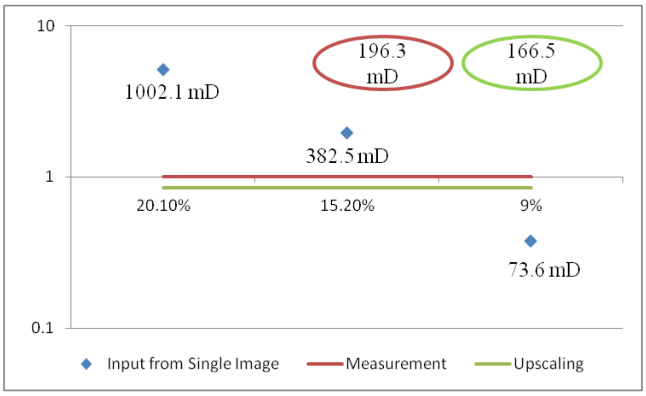

Fig.5. Berea sandstone permeability comparison: estimation permeability of building blocks representative image, upscaling permeability workflow and laboratory data.

There are two pore scale permeability that overestimate and one is underestimate permeability measurement. It shows that permeability prediction on mm scale cannot cover the heterogeneity at core plug scale. The accuracy of applying upscaling permeability workflow is ~85 % through comparison on K_n with lab measurement. It shows that applying this workflow on thin section can covered the heterogeneity at core plug scale and improved prediction of permeability at laboratory scale.

IV. Conclusions

We have demonstrated that our new workflow is efficient to predict laboratory scale permeability of sandstone. The results showed good accuracy with laboratory measurement. This approach is practical, easily repeatable (in real time) and can be used as an alternative method when core plug for permeability information is not available. The possibility to use this method on thin sections from chips, cuttings and rotary sidewall cores that routinely available from wells is also align to obtain permeability distribution information since these samples give good sampling intervals which almost cover whole depth of the wells. The application to thin section from real oil field will be a good challenge for next step of this workflow.

V. References

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