CILAMCE 2017
Florianópolis - Santa Catarina - Brazil

MULTISCALE PORE NETWORK MODELLING APPLIED TO PETROPHYSICAL CHARACTERIZATION OF HETEROGENEOUS CARBONATE ROCKS

I.F. Mantovani[1], A.C. Moreira[1], Z. Jiang[2,3], M.I.J. van Dijke[2,3], C.P. Fernandes[1]

[1]Graduate Program in Materials Science and Engineering (PGMAT), Mechanical Engineering Department (EMC), Federal University of Santa Catarina (UFSC)
[2]Institute of Petroleum Engineering, Heriot-Watt University
[3]International Centre for Carbonate Reservoirs

Abstract. Microstructure system comprehension in porous media is significant in environmental science and technology, in particular water and hydrocarbon reservoirs. In natural materials, such as petroleum reservoir rocks, the characterization of morphology and connectivity contributes to improvements in hydrocarbons recovery strategies (oil and gas). Advances in X-ray microtomography, which is a non-destructive 3D imaging technique, permit observe the details of the internal structure of rocks. Pore-scale imaging studies have mostly focused on homogeneous porous material such as bead packs and sandstone rocks. Sandstones rocks have being studied for a long time, so its porous structure is well known, usually consisting of rounded grains and a short range of pore size. However, carbonate rocks storage besides more than 50% of hydrocarbon reserves in the world is also an important water repository to one quarter of the global population. The porous system of carbonates is often very complex, with a multiple pore-sized system, from nanometers to millimeters, which requires a multiscale analysis. Taking this into account, a pore network modeling of Jiang et al. 2013b was used to characterize five carbonate samples. This method combines two or more networks (in different scales) in order to describe the wide range of pore sizes. The samples were scanned in two resolutions with microCT, course and fine-scale, and then the images were processed to reach the pore networks. The networks were integrated into a single network. Based on the analysis of the integrated networks absolute permeability was estimated for each sample. The results are in a good agreement with petrophysical data.

Keywords: Heterogeneous porous media, X-ray computed microtomography, pore network integration, absolute permeability.

1. INTRODUCTION

The application of X-ray microtomography (microCT) in rock sample analysis has increased recently. Working as a complementation to petrophysical processes, 3D image analysis improved the understanding of the pore structure of rocks. Some parameters are effortlessly determined with images (such as porosity, pore size distribution and surface area), however, permeability estimation is not a trivial task. Petrophysical properties are highly dependent on the pore structure geometry and topology (Wu et al. 2011). The more complex the structure, the more challenge is the determination. In this sense, image analyses have been strongly supported by the use of numerical codes.

Codes based on the Lattice-Boltzmann methods are able to predict fluid flow properties directly from 3D images of the pore space (Manwart et al. 2002, dos Santos et al. 2005, Vogel et al. 2005). Nevertheless, these simulations in realistic rock or soil sample require a powerful computational apparatus and can be time consuming (Jiang et al. 2007). Therefore, methodologies were developed to represent a complex pore system in a simplified pore network. It is compounded by objects with well-known geometry (cylinders and spheres, per example), which enables the use of any desk computational system to predict the petrophysical properties.

Even though the model simplifies the structure, essential features of the porous media are preserved, such as the topology (connectivity) and some geometrical properties (inscribed radius, shape factor and hydraulic radius). Other properties, such as node and bond volume, node spatial position and coordination number, are calculated directly via image analysis (Jiang et al. 2011). Pore networks either can be accomplished from statistical information of a digital representation of the pore space (Thovert et al. 1993, Lindquist and Venkatarangan 1999, Liang et al. 2000, Prodanović et al. 2006) or directly extracted from 3D microtomography images (Lindquist et al. 2000, Silin et al. 2003).

Most methods were developed for homogeneous porous media with narrow ranges of pore size. These procedures, however, are inadequate for predicting properties of heterogeneous pore structures, such as carbonate rocks (Ramakrishnan et al. 2000). Interpreting carbonate rocks is further complicated because they frequently display a complex porous structure containing a multiple porous system with several degrees of connectivity.

Considering the complex structure of some carbonate rocks, a study concerning different scales is required. Knackstedt et al. 2006 evaluate carbonate reservoir samples and discuss the effect of the microporosity scale in the fluid flow. Currently, significant progress has been made in the integration of two or more networks (in different scales) in a single multiscale network (Jiang et al. 2013b, Prodanović et al. 2014). Multiscale pore networks can contemplate different length scales and permit the determination of properties of fluid flow (permeability and capillary pressure) via faster simulations.

The aim of this work is to apply the method of pore network extraction and integration developed by Jiang et al. 2013b to determine absolute permeability of carbonate rocks. Analysis of five samples from carbonate reservoirs and the multiscale analysis were accomplished by means of X-ray microtomography. Although the integration can be performed for several scales, the use of just two different spatial resolutions were considered adequate for the analyzed samples. Considering a tolerable degree of deviation, the determined results are in agreement with petrophysical data.

2. MATERIALS AND METHODOLOGY

The carbonates under study are reservoir rock samples from two Brazilian oil/geological fields, denominated as Field A and B. The samples are plugs with 38 mm diameter x 45 mm in height for Field A and 25 mm diameter x 30 mm in height for Field B. As the pore structure of carbonate rocks are very complex, analyses based on a single tomographic image could fail in evaluating several microstructural factors.

In the present work, the pore structure of the samples was investigated through microCT images acquired with two different spatial scales. In order to capture the macropores, the whole plug was imaged first with a coarse-scale (Cs), whereas a smaller subsample of ~ 5 mm diameter was imaged with a higher resolution. The second acquisition termed fine-scale (Fs) was accomplished in order to resolve the sub-micron pore system. The microtomography results presented in this paper were obtained with a microCT 1173 scanner (coarse-scale) and 1172 scanner (fine-scale), both from SkyScan/Bruker. A VersaXRM-500 (fine-scale) from XRadia/Zeiss was also used. 2D slices of each sample (in both scales) are shown in Fig. 1.

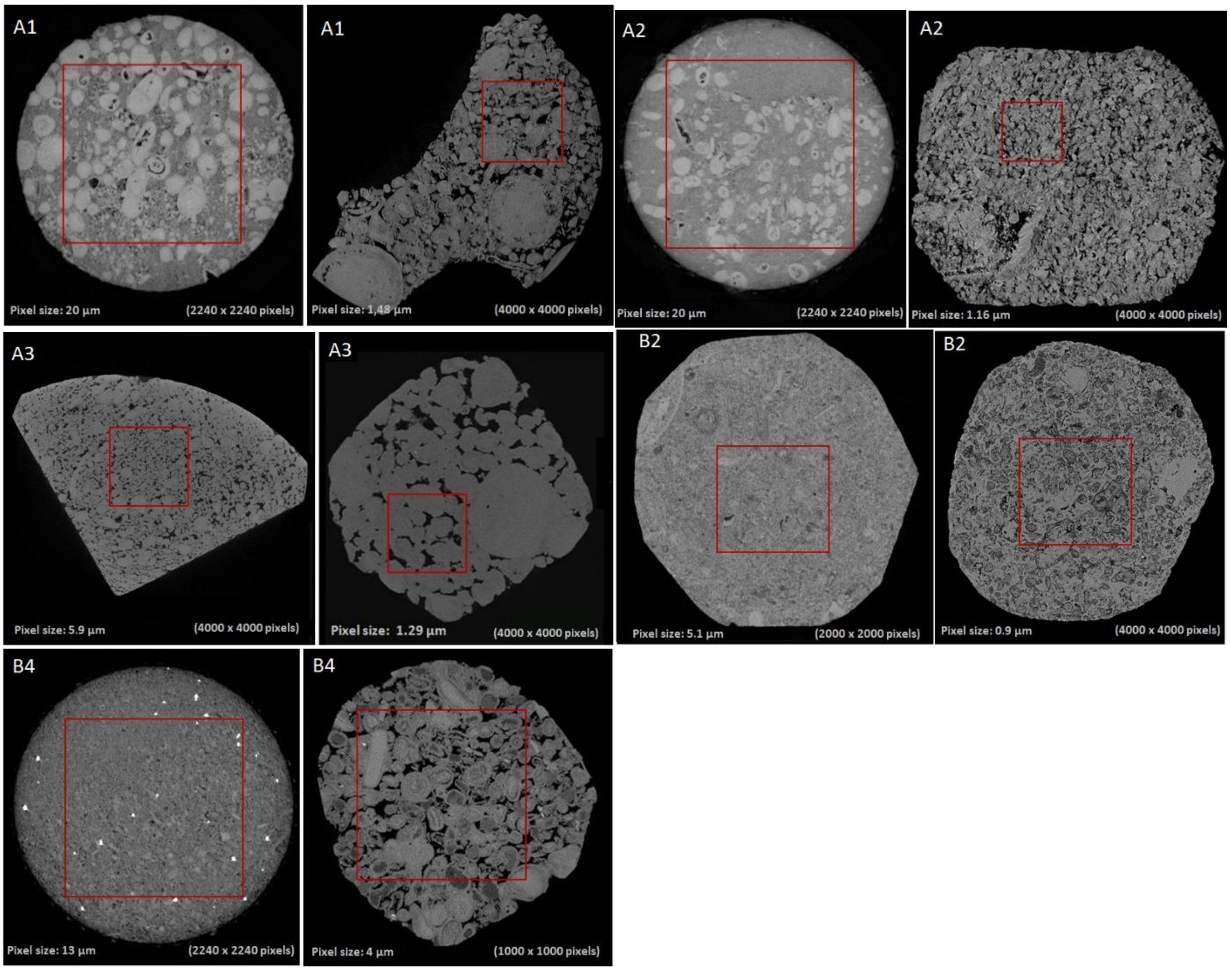


Figure 1. MicroCT 2D slice of samples in the coarse and fine scales, as described. The square indicates the region of interest used in the image processing.

Prior to quantitative image analysis, 2D slices were processed with non-local means filter (Buades et al. 2005) followed by unsharp mask filter (Pratt 2001). Although the application of filters improved the segmentation process diminishing noises, the fine structures and details of the sample were preserved.

Some samples under study, such as A1 and A2 (Fig. 1), have visually well-defined solid and porous regions in the coarse-scale, which allows the image segmentation in three regions: pore, solid and non-solved. The non-solved region (or undefined) has an intermediary gray level which is difficult to ascertain if it is either composed by a different material or by sub-micro pores. In this particular case, the 3D image is divided into white, black and gray regions. Otherwise, the image is segmented into two regions: pore and solid (white and black, respectively). In this work, both cases occurred. In Fig. 2 the multiscale analysis process with three-region (Cs) segmentation from the sample and two-region (Fs) segmentation from subsample is shown.

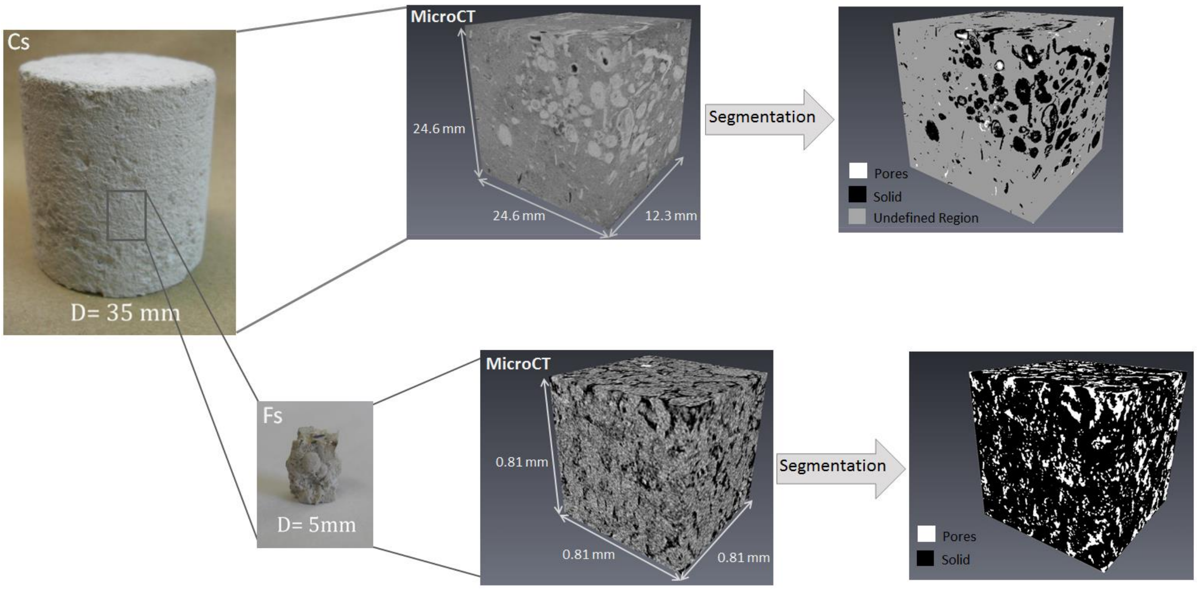


Figure 2. Segmentation of coarse-scale (Cs) in three regions and fine-scale (Fs) in two regions and subsequent quantification. Acquisition of Cs microCT images from the plug (D= 35 mm), and from de sub-volume of 5= mm microCT images acquired Fs.

In terms of computational time, petrophysical analysis carried out with simplified models of pore networks is quick and efficient. Jiang et al. 2013b developed the method used in this work, in which pore networks (with different scales) are integrated into a single multiscale network. To generate a multiscale network, firstly, individual pore networks are extracted from 3D images at different resolutions of a sample (Jiang et al. 2007). Secondly, from each extracted network, statistical information is derived from network geometry and topology in terms of probability distributions of a single property (such as volume, radius, shape factor, etc.) and correlation functions between two or more properties. A stochastic network within any specified domain of arbitrary size can be generated from these statistics. The stochastic network is equivalent to the corresponding original network in terms of morphology and flow properties (Jiang et al. 2011).

Thirdly, within an arbitrary domain, a coarse-scale network is created or copied and then a stochastic fine-scale network is generated in the space not occupied by the coarse-scale network (Jiang et al. 2012). In images segmented in three regions, the Fs network elements (nodes and bonds) are uniformly distributed throughout the space of the non- solved region (gray color in Cs Fig. 3). Finally, the cross-scale connections are created connecting coarse-scale nodes to fine-scale nodes using fine-scale bonds. It is important that the scales involved in the multiscale network have a range of overlapping pore sizes. This condition ensures that the method will have enough statistical information to understand the connections at different length scales. Figure 3 shows the schematic workflow for the method of pore network integration of two segmented 3D images in different scales.

Using multiscale networks generated with this method, porosity, absolute permeability and network property results are presented to demonstrate the importance in a multiscale study in heterogeneous materials. These outcomes were compared with petrophysical laboratory data kindly provided by Petrobras.

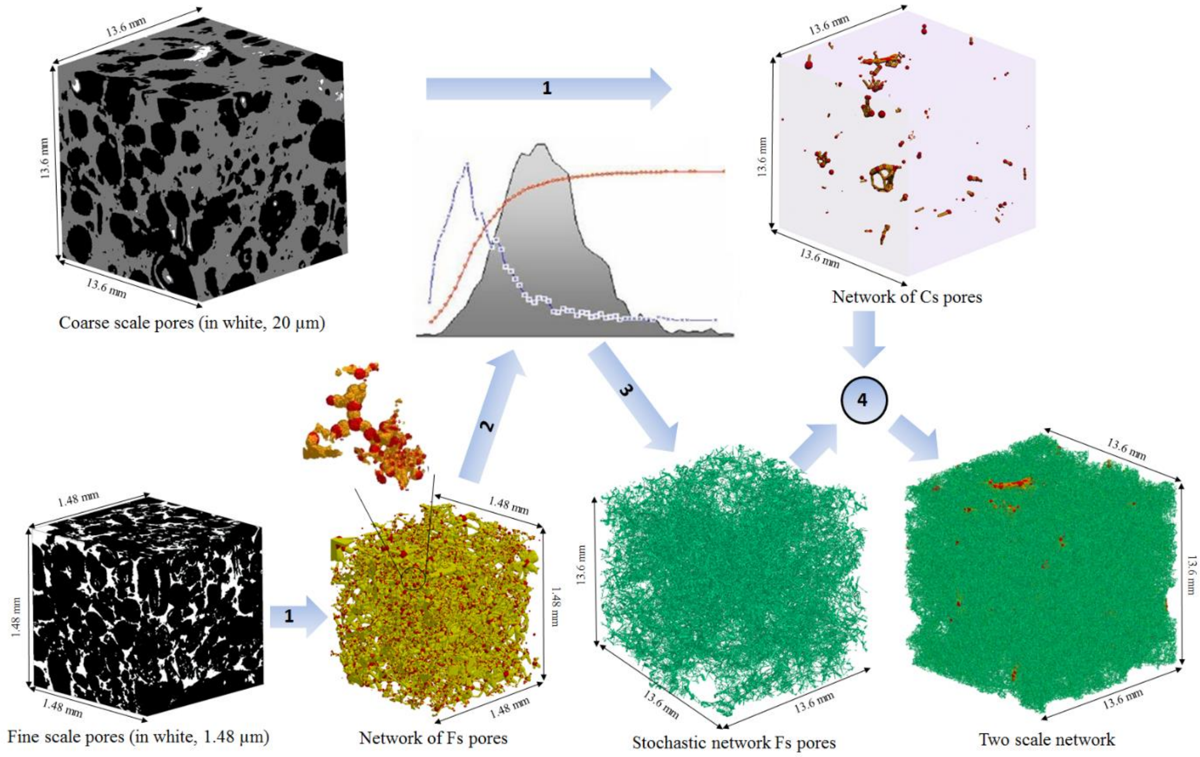


Figure 3. Integration between a coarse-scale (Cs) and fine-scale (Fs) network: 1. Extraction of Cs pore network from the coarse-scale segmented microCT image. Similarly, Fs network is derived from fine-scale image; 2. Fs network is characterized in terms of probability and correlation functions; 3. Fs stochastic network is created with the same Cs network domain; 4. Integration of the two networks in a multiscale network based on the information about cross-scale connectivity (modified from Jiang et al. 2013a).

3. RESULTS AND DISCUSSIONS

The samples properties were determined in subimages due to the computational evaluation of macroscopic properties demanding a large amount of computational operations, which is sometimes unavailable. This region of interest (ROI) has to correspond to a representative elementary volume (REV), which should be smaller than the size of the sample, but larger than a single pore to permit the meaningful statistical average required in the microstructural property in the study (Bear 1988).

Defining a REV is always a challenge, even for a simple property as porosity. Therefore, the porosity in terms of ROI size (for both scales) was evaluated and the results were satisfactory. In addition, due to computational limitations, the highest computational capacity available was used for the quantification of data in this work. Details of the process and results can be found in (Mantovani 2013). Figure 1 shows the ROI sizes used in each image defined by a red square.

Networks were extracted from the pore region of microCT images segmented in both coarse and fine scale as described in Fig. 3. The coarse-scale concerns the macroporosity, while the fine-scale represents the micropores. Even all the samples are carbonate rocks they quite dissimilar, their pore systems are complex in different ways. For example, samples A1 and A2 have a solid phase very well defined in Cs which represents 46.21% and 21.40% of the total volume analyzed, respectively. In this kind of rock, over the network integration, the elements (nodes and bonds) of the Fs network have to be uniformly distributed throughout the space not occupied by coarse-scale and the solid phase, as shown in Fig. 4b.

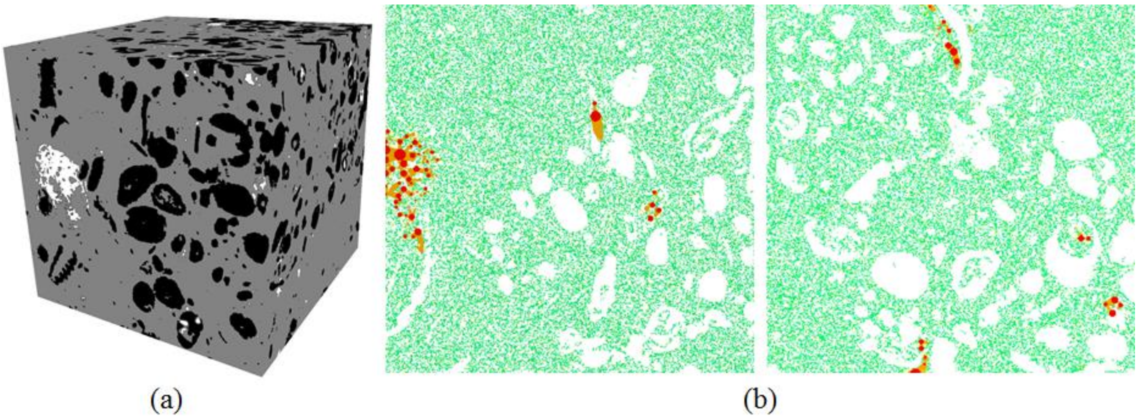


Figure 4. A segmented subvolume (a) of a three region image of 500x500x500 voxels of Cs. Pore, solid and non-resolved regions are white, black and gray phases, respectively; (b) two example images of 2D slices of multiscale pore network with fine-scale elements (in green) uniformly distributed only throughout regions of sub-scale resolution, indicated in gray in (a). Coarse-scale network is red and yellow in (b).

The location of Fs network elements can change the value in the prediction of some petrophysical properties. The impact depends on the amount of the solid phase and the distribution in the sample. In Jiang et al. 2013a a case of study shows how the location of the fine-scale elements influence the petrophysical properties. The authors observed a major impact in predicted absolute and relative permeability just by modifying the way to deal with the fine-scale.

In addition to the location of the Fs network elements, the amount used in the integration is also important. Considering that, the fine scale stochastic network is far bigger than its original network, the multiscale network resultant would be extremely large with millions of elements (Jiang et al. 2013b). To overcome these problems and to keep the pore network at a manageable size for any desk computer available, it was used 10% of the Fs network elements. Although these two issues influence the multiscale network porosity, van Dijke et al. 2011 and Jiang et al. 2013b, shows that the absolute permeability stabilizes from 10% of fine nodes and bonds.

Several parameters can be obtained from a pore network, such as number of nodes and bonds, coordination number, shape factor, etc. Besides petrophysical properties, such as absolute and relative permeability, capillary pressure, can be determined. In this work, absolute permeability was predicted from individual pore network (each scale) and after the integration using the code developed by (Ryazanov et al. 2009). The network properties as well as the permeability of one sample is shown in Fig. 5 as an exemple of many quantifications, which is possible to determine from a pore network. Porosity and permeability values, predited from the pore network and mesured in the laboratory are shown in Table 1.

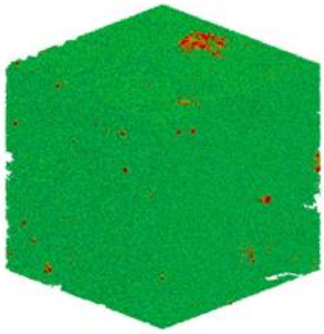
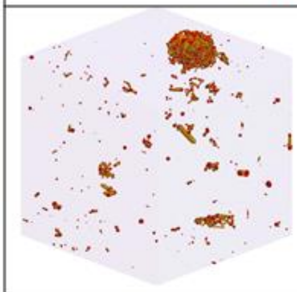
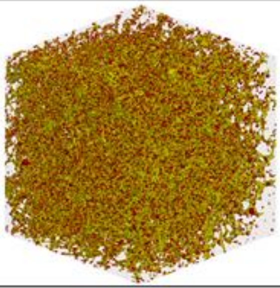
Network view	*Network properties*		**Two-scale network**	
Coarse scale network				
	Nodes	1401		
	Bonds	2327		
	Connection	0.95		
	Porosity (%)	1.07		
	Permeability (mD)	0.85		
Fine scale network			*Network properties*	
	Nodes	61160	Nodes	85671
	Bonds	101553	Bondes	142972
	Connection	3.28	Connection	3.01
	Porosity (%)	13.08	Porosity (%)	13.00
	Permeability (mD)	46.31	Permeability (mD)	14.04

Figure 5. Pore network view and properties determined from a multiscale network of sample A2.

Table 1. Spatial resolution, porosity and absolute permeability on each scale (individual) and multiscale network and laboratory data.

Sample	**Individual network**			**Multiscale network**		**Laboratory data**	
	Pixel size	ϕ (%)	k (mD)	ϕ (%)	k (mD)	ϕ (%)	k (mD)
A1	20.00	1.30	2.74	15.12	207.43	23.50	176.00
	1.48	21.50	1736.52				
A2	20.00	1.07	0.85	13.00	14.04	25.60	38.00
	1.16	13.08	46.31				
A3	5.90	15.84	2159.74	17.71	2537.36	21.30	2300.00
	1.29	14.34	471.71				
B2	5.10	1.52	0	6.23	13.02	21.20	2.60
	0.90	4.73	0.14				
B4	13.00	1.59	0	11.47	209.98	27.80	280.00
	4.00	14.68	466.94				

The importance of a multiscale study in carbonate rocks is highlighted in the images shown in Fig. 1. One can observe that more fine structures become more noticeable as the spatial resolution improves. It is also evident that the morphology of the structure changes from one scale to another. This complexity is confirmed by the laboratory data (table 1), which shows samples with quite constant porosity (~21 - 28%) in contrast to the high variability of permeability (~3 - 2300 mD).

According to Lucia 1983, 1995 and Melim et al. 2001 carbonate rocks with similar porosity may present distinct permeability values. Carbonate rocks typically show no simple relationship with porosity. This behavior depends on the heterogeneous pore distribution, pore type, pore connectivity, and grain size, rather than on the quantify of pore space. Experimental data presented in Table 1 shown examples of this, as samples A3 and B2 with porosity value of 21.3 % and 21.2 %, whereas permeability values are 2300 mD and 2.6 mD, respectively.

For samples in which Cs network is highly permeable, as A3 sample, the integration of the Fs network does not improve its permeability significantly. In this case, the percolation process is ruled by macropores. On the other hand, if the Cs network is poorly connected, the integration with the fine scale may change the absolute permeability significantly enhancing the determination. This is due to method that, during integration, connects nodes from fine and coarse scales creating a flow through the network and, consequently, resulting in a measurable property.

Although multiscale network absolute permeability is not substantially influenced by the fine scale after 10% fraction of elements, the porosity is (Jiang et al. 2013b). In an overall point of view, the fine scale is stochastically represented by means of its properties. These properties are uniformly distributed throughout the space of the non-solved region. Consequently, the porosity increases linearly with the Fs percentage (Jiang et al. 2013b).

Proper absolute permeability predictions accomplished in single scale networks are successfully reported in literature (Jiang et al. 2007, Ryazanov et al. 2009, Al-dhahli et al. 2012). However, a multiscale system demands a multiscale approach in acquiring the microCT images with small gap in pore size between the scales used in an integration network. This should ensure beneficial statistical measurements of the connections between the scales and provide enough information for the model to create coarse scale and fine scale bonds.

4. CONCLUSIONS

Using the method of Jiang et al. 2013b to extract the pore network from 3D images at different length scales and integrated in a multiscale network, porosity and absolute permeability in real reservoir rocks were predicted. The method of modeling heterogeneous porous systems in a pore network is widely used in numerical simulation of fluid flow properties in order to decrease computational efforts.

Encouraged by the multiscale characterization, the model was applied in samples of carbonate rocks with complex porous systems measured by microCT images. The outcomes of this study showed the necessity of multiscale treatment in the description of these carbonates in order to understand their wide range of pore size.

Absolute permeability data determined in this work must be considered as estimations. The authors only intend to contribute to a better comprehension of the issue involving fluid flow in multiscale structures by means of pore networks. Therefore, the results predicted in this work in multiscale networks are reasonable compared to laboratory data measurements. Consequently, multiscale systems results are more comparable to petrophysical data than those from individual scales, highlighting the significance of the integration. The focus of the integration relies on keeping the right connection between scales. Although this preservation is not a simple achievement, this is certainly the main subject to be improved.

Acknowledgements

CENPES/Petrobras is acknowledged for financial support and kindly providing samples and petrophysical data used in this paper. The research centers LARX/UEL, LAMIR/UFPR and Lagesed/UFRJ for supporting this research. CNPq and CAPES are recognized for their financial support.

REFERENCES

Al-dhahli, A.; Geiger, S.; van Dijke, M. I. J.; 2012. Accurate modelling of pore-scale film and layer flow for three-phase eor in carbonate rocks with arbitrary wettability. *SPE Improved Oil Recovery Symposium. Society of Petroleum Engineers.*

Bear, J.; 1988. Dynamics of Fluids in Porous Media. Dover Publications, inc., New York.

Buades, A.; Coll, B.; Morel J-MJ-M (2005) A non-local algorithm for image denoising. *CVPR '05 Proceedings of the 2005 IEEE Computer Society Conference on Computer Vision and Pattern Recognition (CVPR'05),* v. 2, pp. 60-65.

dos Santos, L.O.E.; Ortiz, C.E.P.; de Gaspari, H.C.; Haverroth, G.E.; Philippi, P.C., 2005. Prediction Of Intrinsic Permeabilities With Lattice Boltzmann Method. 18th Int. Congr. Mech. Eng.

van Dijke, M. I. J.; Jiang, Z.; Wu, K.; Wang, C.; Al-Abr, M.; Sorbie, K. S. e Couples, G. D. (2011). Prediction of multi-phase flow properties of heterogeneous rocks based on stochastic pore-network generation. *IFP Energies nouvelles (France).*

Jiang, Z.; van Dijke, M. I. J.; Geiger, S.; Kronbauer, D.; Mantovani, I. F.; & Fernandes, C. P., 2013a. Impact Of the Spatial Correlation of Microporosity on Fluid Flow in Carbonate Rocks. *Society of Petroleum Engineers*.

Jiang, Z.; van Dijke, M. I. J.; Sorbie, K. S.; Couples, G. D., 2013b. Representation of multi-scale heterogeneity via multi-scale pore networks. *Water Resources Research*, v. 49, pp. 5437–5449.

Jiang, Z.; van Dijke, M.I.J.; Wu, K.; Couples, G. D.; Sorbie, K.S.; Ma, J., 2012. Stochastic Pore Network Generation from 3D Rock Images. *Transp Porous Media*, vol. 94, pp. 571–593.

Jiang, Z.; Wu, K.; Couples, G. S.; van Dijke, M. I. J.; Sorbie, K. S.; Ma, J., 2007. Efficient extraction of networks from three-dimensional porous media. *Water Resources Research* v. 43, pp. 1–17.

Jiang, Z.; Wu, K.; Couples, G.D.; Ma, J., 2011. The impact of pore size and pore connectivity on single-phase fluid flow in porous media. *Advanced Engineering Materials*, vol. 13, n. 3, pp. 208–215.

Knackstedt, M. A.; Arns, C. H.; Ghous, A., Sakellariou, A., Senden, T. J., Sheppard, A. P., Sok, R. M., Nguyen, V., Pinczewski, W. V., 2006. 3D imaging and characterization of the pore space of carbonate core; implications to single and two phase flow properties. *SPWLA Annu Logging Symp 1–15.*

Liang, Z.; Ioannidis, M. A. e Chatzis, I., 2000. Geometric and topological analysis of three-dimensional porous media: pore space partitioning based on morphological skeletonization. *Journal Colliod Interface Sci*., vol. 221, pp.13–24.

Lindquist, W.B.; Venkatarangan, A., 1999. Investigating 3D geometry of porous media from high resolution images. *Phys Chem Earth, Part A Solid Earth Geod*, vol. 24, pp. 593–599.

Lindquist, W. B.; Venkatarangan, A.; Dunsmuir, J. e Wong, T., 2000. Pore and throat size distributions measured from synchrotron X-ray tomographic images of Fontainebleau sandstones. *Journal Geophys Research: Solid Earth,* vol. 105, pp. 21509–21527.

Lucia, F.J., 1983. Petrophysical parameters estimation from visual description of carbonate rocks: a field classificaton of carbonate pore space, *Journal Petroleum Technology,* vol. 35, n. 03, pp. 626–637.

Lucia, F.J., 1995. Rock-fabric/Petrophysical Classification of Carbonate Pore Space for Reservoir Characterization, *Bulletin American Association Petroleum Geologists*, vol. 79, n. 9, pp. 1275–1300.

Mantovani, I.F., 2013. *Microtomografia e nanotomografia de raios X aplicada à caracterização multiescalar de sistemas porosos carbonáticos.* PhD thesis, Federal University of Santa Catarina.

Manwart, C.; Aaltosalmi, U.; Koponen, A.; Hilfer, R.; Timonen, J., 2002. Lattice-Boltzmann and finite-difference simulations for the permeability for three-dimensional porous media. *Physical Review E*, vol. 66, vol. 1, pp. 1–32.

Melim, L.A.; Anselmetti, F.S.; Eberli, G.P., 2001. The importance of pore type on permeability of Neogene carbonates, Great Bahama Bank. In: Subsurface Geology of a Prograding Carbonate Platform Margin, Great Bahama Bank: Results of the Bahamas Drilling Project., (ed. Ginsburg, R.N.), SEPM Special Publication, vol. 70, pp. 217–240.

Pratt, W.K., 2001. Digital Image Processing. *John Wiley & Sons*, Inc., New York, USA

Prodanović, M.; Lindquist, W.B.; Seright, R.S., 2006. Porous structure and fluid partitioning in polyethylene cores from 3D X-ray microtomographic imaging. Journal Colloid Interface Science, vol. 298, pp. 282–297.

Prodanović, M.; Mehmani, A.; Sheppard, A., 2014. Imaged-based multiscale network modelling of microporosity in carbonates. Geological Society of London, Special Publication, 406.

Ramakrishnan, T.S.; Ramamoorthy, R.; Saito, N.; Flaum, C., 2000. Method for interpreting carbonate reservoirs. Copending U.S. patent application Ser. No. 098/189,025, filed (Nov. 10, 1998).

Ryazanov, A. V.; van Dijke, M.I.J.; Sorbie, K.S., 2009. Two-phase pore-network modelling: Existence of oil layers during water invasion. *Transport Porous Media*, vol. 80, n. 1, pp. 79–99.

Silin, D.B.; Jin, G.; Patzek, T.W., 2003. Robust Determination of the Pore Space Morphology in Sedimentary Rocks. In: SPE Annual Technical Conference and Exhibition. *Society of Petroleum Engineers.*

Thovert, J.F.; Salles, J.; Adler, P.M., 1993. Computerized characterization of the geometry of real porous media: their discretization, analysis and interpretation. *Journal of Microscopy* vol. 170, n.1, pp. 65–79.

Vogel, H-J.; Tölke, J.; Schulz, V.P.; Krafczykb, M.; Rotha, K., 2005. Comparison of a Lattice-Boltzmann Model, a Full-Morphology Model, and a Pore Network Model for Determining Capillary Pressure–Saturation Relationships. Vadose Zone Journal, vol. 4, n. 2, pp. 380-388.

Wu, K., Jiang, Z.; Ma, J.; Couples, G. D.; van Dijke, M. I. J. e Sorbie, K.S., 2011. Multiscale pore system reconstruction and integration. Proc. SCA Symposium, Austin, Texas.