BRIDGING PORE TO CORE-SCALE FLOW PROPERTIES USING PORE-SCALE MODELING AND COREFLOOD SIMULATION

Hiroshi Okabe [1,2]

[1] Japan Oil, Gas and Metals National Corporation, 1-2-2 Hamada, Mihama-ku, Chiba, 261-0025, Japan

[2] Department of Earth Science and Engineering, Imperial College London, SW7 2AZ, UK

This paper was prepared for presentation at the International Symposium of the Society of Core Analysts held in Toronto, Canada, 21-25 August 2005

ABSTRACT

Simulating a coreflood experiment is more than a good exercise. It is the only way to deduce flow properties of a heterogeneous rock or when the capillary effects are important. Numerical simulation is very often a better approach than the traditional method such as JBN, especially for heterogeneous rock samples, to understand detailed flow behavior. Since many parameters are involved during history matching of the experiment, the matching process becomes more complicated as the core-scale heterogeneity is increased. In order to optimize matching parameters efficiently, an automated history-matching program using the Genetic Algorithm has been developed. The program is used to interpret coreflood displacements on heterogeneous carbonate cores and successfully predicts a reasonable set of relative permeability and capillary pressure curves within given pore-types, which are the representative classes of void structures of the rock. Although the program numerically estimates flow properties for each pore-type, it is better if these properties are explained using pore-scale modeling, which supports these flow properties derived by the coreflood simulation.

Core-scale heterogeneity is assigned by the key pore-types that are characterized by petrographical and petrophysical analysis. Pore-scale modeling simulates multiphase flow through each pore-type. Predicted flow properties using pore-scale modeling are consistent with those derived by the coreflood simulation using the Genetic Algorithm. The combination of pore and core-scale analyses improves the understanding of flow through heterogeneous porous media and the method bridges pore to core-scale analysis.

INTRODUCTION

Predicting representative sets of relative permeabilities and capillary pressure is of great importance for reliable reservoir simulation and management. These transport properties define flow behavior in porous media and they critically depend on the geometry and topology of the pore space, the physical relationship between rock grains and the fluids, and the conditions imposed by the flow process. Due to the importance of the flow properties and the difficulty to obtain them appropriately, much effort has been devoted to derive the transport properties theoretically, numerically and experimentally [1, 2]. Even when the properties are successfully obtained in the laboratory, there is a missing link between the laboratory scale and the larger field scale because the properties are scale-dependent due to the heterogeneous nature of rocks. Although smaller pore-scale physics relates to larger scale phenomena, it is not practical to conduct a flow simulation of naturally heterogeneous reservoir at the field scale using pore-scale physics. Therefore, many upscaling techniques have been developed to alleviate the enormous computational cost of flow modeling [3]. A reasonable upscaling technique from plug cores to a whole core has been recently proposed [4]. The method has successfully predicted the relative permeabilities of the whole core using the characteristics of smaller plug cores. It is important that the degree of heterogeneity is appropriately described in the core unless the rock is homogeneous. The core was divided into key pore-types in order to predict flow properties in each pore-type. The flow properties of each pore-type were estimated through coreflood simulation combined with the Genetic Algorithm (GA); however, the properties obtained by the numerical solution were not physically explained. Although coreflood simulation is useful in obtaining a set of flow properties with a reasonable range, it is better that derived flow properties are explained at the pore-scale in order to understand the displacement physics and as a consistency check on the results. Therefore, pore-scale modeling is used to support these flow properties in order to bridge pore to core-scale properties.

As explained below, the coreflood experiments and their simulations are described first. To characterize flow behavior at the core-scale, petrographical and petrophysical analysis is used to determine key pore-types. An effective optimization process is necessary to reproduce the coreflood displacements by the flow simulation; therefore, the Genetic Algorithm is applied to optimize the simulation. The main focus of the paper is to bridge the pore to core-scale flow properties. It is necessary to have a representative network structure as an input for the pore scale network model. To obtain the network, a reference network is modified to fit the target reservoir rock by matching the mercury injection capillary pressure. The process of modification is discussed first, and followed by the prediction of flow properties using the network model.

COREFLOOD SIMULATION

Coreflood experiments and pore-type analysis

A whole core of heterogeneous rock recovered from a Cretaceous carbonate reservoir in the Middle East was used for the water flooding experiment with in-situ fluid saturation monitoring by X-ray CT, which has a resolution of 0.35mm. The whole core is mainly composed of algal bioclastic peloidal packstone/grainstone and has an average porosity of 0.322 and air permeability of 30.7mD. After the unsteady-state oil/water displacement in the whole core, one inch-diameter plug cores were drilled out from it (Figure 1 left). A series of water displacements on the plug cores was carried out at Swi restored conditions and one of the experimental results is compared with the simulation in Figure 1 right. Then all the samples were sliced for detailed core characterization. Petrographical and petrophysical analyses were used to determine the three key pore-types: poorly to moderately sorted bioclastic-peloidal grainstone/packstone (Pore-type A); fine grained peloidal packstone (Pore-type B); and algal fragment (Pore-type C).

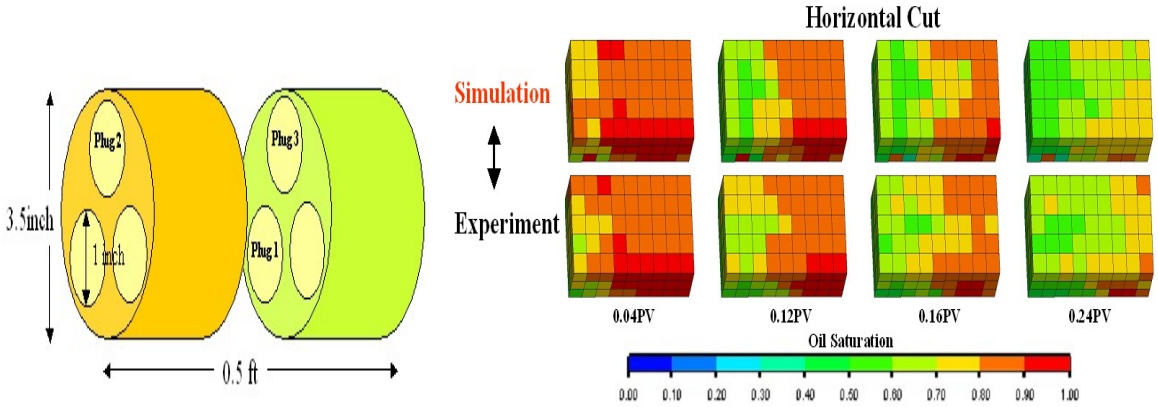

Figure 1. Location of 1 inch-diameter plug cores in the whole core (left) and oil saturation distribution during a water flooding experiment on a carbonate plug core is compared with that predicted by the coreflood simulation (after the history matching). This core plug drilled out from the whole core has porosity of ϕ=0.329 and permeability of k=20.1mD, which are different from the properties of the whole core due to its heterogeneity.

Coreflood simulation using the Genetic Algorithm

The water displacements are reproduced by constructing 3D coreflood simulation models as the simulations are a reliable approach to understand flow through heterogeneous porous media [5]. However, it is often difficult to obtain a unique result and it might take a long time to reach the optimum solution due to the many parameters involved. An efficient procedure, therefore, is necessary to reproduce the experiments using the coreflood simulation. There are many optimization algorithms to find the solution for such problems. However, some

methods encounter local minima for the solutions when the problem is complicated and their search space is widely spread. The Genetic Algorithm is one of the most suitable methods to optimize parameters for complicated problems [6-8]. An automated history-matching program called GEMAP (GEnetic algorithm MAtching Program) has been developed to improve the accuracy and the efficiency of the coreflood simulation [9].

The Genetic Algorithm uses Darwin's theory of evolution. An organism that fits to a certain environment can survive longer and its genetic information is transmitted to new offspring by recombining (crossover) and mutating those genes. The fitness of an organism is measured by success of the organism in its life. Applying the Genetic Algorithm to history-matching coreflood experiments, the problem has to be described properly in order to select the optimum solution from multiple realizations. The program optimizes the unknown parameters for relative permeabilities and capillary pressure through reasonable reproduction of the experimental data such as changes of fluid saturation and differential pressure during displacement as shown in Figure 2. The program uses Corey-type normalized relative permeabilities and capillary pressure, which are defined by four and five unknown coefficient parameters respectively (Eqs.(1)-(7) in [9]). To optimize the unknown parameters and to increase the degree of matching accuracy, the difference between experimental data and simulation results are compared. For example, water saturations in every simulation grid block can be compared with the experimental data taken by X-ray CT. More details of the program are given in [9].

The coreflood simulation model is composed of 5mm cubes in consideration of the measurement resolution of a minipermeameter and it is constructed from available data such as porosity, Swi and Sor derived from X-ray CT, minipermeameter permeability and distribution of pore-types described by the geologist. The processes of history matching for three experiments determine unknown parameters of relative permeabilities and capillary pressure for each pore-type. Firstly unknown parameters of Pore-type A are predicted by simulating one particular experiment because the target core is composed of 98% of the pore-type. Then the optimization of Pore-type B and C are carried out similarly on two cores, which have different ratios of defined pore-types. Consequently, a set of relative permeability and capillary pressure curves are derived for the three pore-types. Figure 3 shows a set of the normalized curves of relative permeabilities and capillary pressure predicted from three different plug cores.

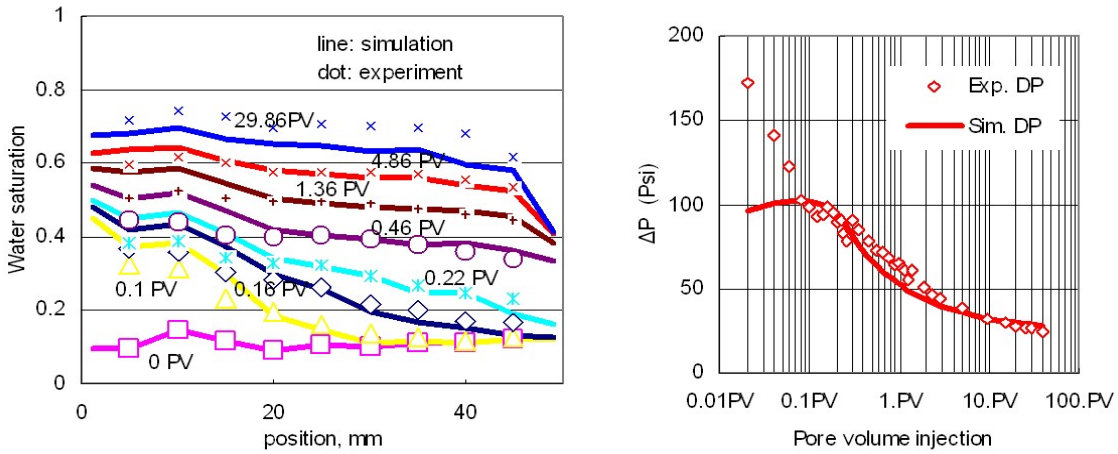

Figure 2. Reproduction of water saturation profiles and the differential pressure during a displacement using coreflood simulation. Reproduction of the oil saturation distribution has been shown already in Figure 1.

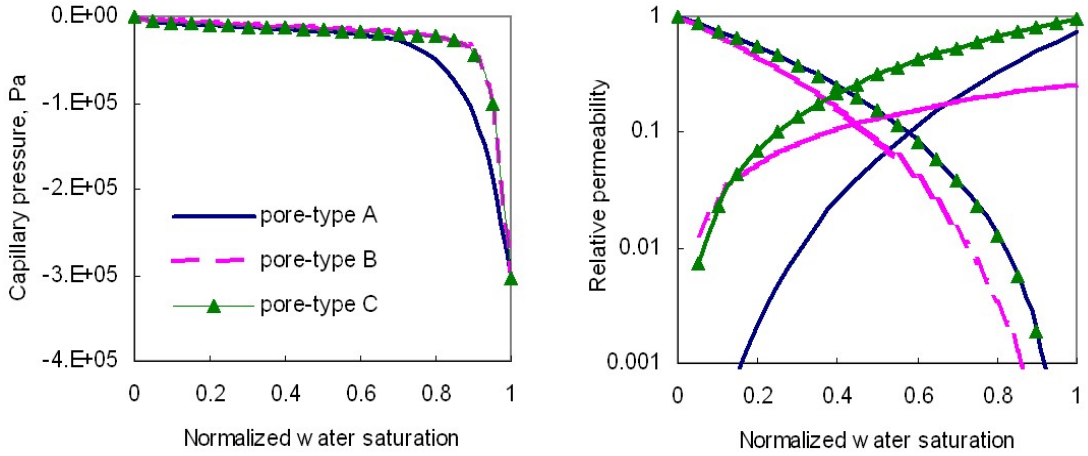

Figure 3. A set of the normalized curves of capillary pressure and relative permeabilities for each pore-types derived by the coreflood simulations (The samples are strongly oil-wet).

PORE-SCALE MODELING

Network modification

Pore-scale network modeling uses an idealized network described by a lattice of pores connected by throats to predict multiphase flow properties such as relative permeabilities and capillary pressure [10]. The network of the rock structure typically consists of thousands of pores and throats within a few millimeters cubed. Most of the networks are traditionally described by a regular lattice, which ignores some of the complicated topology that occurs in realistic porous media. The methods have been developed to construct networks from

small-scale data such as mercury injection capillary pressure. However, it is demonstrated that matching only porosity, permeability and capillary pressure does not guarantee uniqueness of the solution from the generated networks [11]. In order to increase the predictive capabilities of pore-scale modeling, a topologically disordered network that realistically represents the real pore structure is required. To generate a network it is first necessary to have a three-dimensional voxel-based pore-space representation that is constructed by either a direct imaging technique such as micro-CT scanning [12, 13], stochastic methods [14-16], or object-based approaches [17-19]. Although X-ray microtomography is becoming gradually applied to describe porous media at resolutions of around a micron, the resolution is not sufficient to image the sub-micron size pores that are abundant in carbonates [20], which can presently only be imaged by 2D techniques such as scanning electron microscopy (SEM). Even though the 3D voxel-based representation of the pore space is successfully generated in the first process, the second process to extract an equivalent network of pores and throats is not simple. A number of different methods have been proposed to extract a network from a 3D pore space image [21-23]. Bakke and Øren [18] successfully produced networks from images generated using their process-based methods. Despite the development of several promising algorithms and successful tests on the pore structures there is, at present, no method that can routinely and reliably extract networks from 3D images. The use of pore-scale modeling, therefore, is currently limited by the shortage of such appropriate networks derived from 3D pore space images. Valvatne and Blunt [24], however, proposed a methodology for combining a realistic network representing Berea sandstone with conditioning to experimental capillary pressure to predict flow properties of a variety of different porous media. We will use this approach to obtain representative networks using capillary pressure data since the two-step approach to extract the network for our carbonate rock is currently difficult due to the reasons mentioned above. Topological information of a reference Berea network such as relative pore locations and coordination numbers is kept while tuning the properties of the individual network elements. The method could reproduce a range of experimental data from several rocks [24].

The distribution of throat size in the network is the main property used to modify the reference structure to represent the target pore-type. Capillary pressure typically gives us the throat size distribution based on a bundle of capillary tubes assumption for porous media. The derived distribution can be used as the initial guess; however, the network modified using the distribution cannot reproduce the experimental capillary pressure since the hypothesis fails to account for the interconnected nature of real porous media. The distribution of throat sizes is modified until an adequate match to the experimental capillary pressure is obtained. Inscribed radii are assigned from the modified distribution while preserving the rank order of pores and throats, which means that the largest throat is kept as the largest radius in the network. Mercury injection capillary pressure is used to modify the

network in the study to obtain the network for the carbonate samples. Figure 4 shows one of matched capillary pressure curves and predicted throat size distributions for all three pore-types.

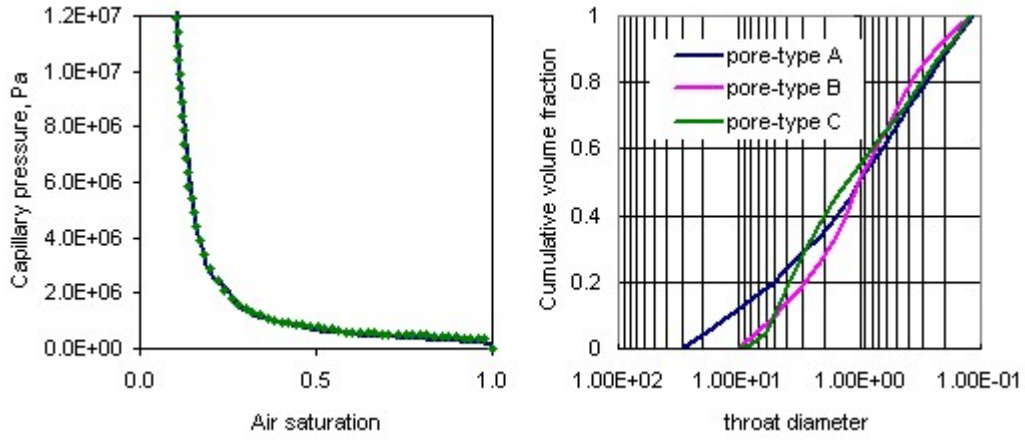

Figure 4. A matched capillary pressure of pore-type C after modifying the reference network (left) and derived throat size distributions for all three pore-types using the same manner (right).

Network model

The quasi-static network model is used to simulate primary oil flooding, wettability alteration and subsequent cycles of water and oil flooding. More details including model description and related equations can be found in [24]. The model uses a topologically equivalent network of pores and throats, rather than a regular lattice network. The individual elements of a network have location, radius and volume. In addition the cross-sectional shape of individual pore and throat are described by the shape factor, $G = A/P^2$, where A is the cross sectional area and P is the perimeter length. Angular corners of network elements such as triangular shapes can model the remaining wetting layers. After primary drainage, the part of the rock exposed to the oil may have its wettability altered. Three main processes, which are piston-like displacement, pore body filling and snap-off, are modeled at the pore-scale.

Predicting flow properties to bridge pore to core-scale

A 10mm plug sample is selected to have only one pore-type, which is classified as pore-type A, B or C, and it is used for the measurement of mercury injection capillary pressure in order to predict throat size distribution for the modified network using the process has explained above. The measured capillary pressure is, therefore, the key to describe an appropriate network modified from the reference network. The permeability, measured on the larger core

from which a 10mm sample is taken, is also well reproduced during the modification process. The modified network for each pore-type is used to predict flow properties. Starting from the network filled fully with water, primary drainage to displace water by oil is simulated using pore-scale model. The displacement is controlled by the capillary pressure. The part of the rock exposed to the oil after primary drainage may have its wettability altered. The wettability on the 10mm plug sample, which is used for the network modification, is not directly measured. Instead of the direct measurement on the sample, the measured wettability is available only for the larger plug cores taken from near the target sample. The Amott wettability indices show oil-wetness and vary widely from -0.3 to -0.9. Due to the absence of original wettability of the each pore-type, the wettability of the pore-type should be iteratively varied to understand its effect on the flow and mainly to reproduce the relative permeability and capillary pressure curves numerically predicted by the coreflood simulation assisted by the Genetic Algorithm. Relatively weaker oil-wetness than the available wettability characteristics after the primary drainage can reproduce the range of both relative permeabilities and capillary pressure for the waterflooding process as shown in Figure 5. The contact angle after aging ranges between 65 and 120 degrees. The negative capillary pressure is well reproduced for all the pore-types except in the very high water saturation region, where the capillary pressure at the core-scale may need to be redefined using a different formulation. The relative permeabilities at the pore-scale are also consistent with those predicted by the coreflood simulations although the relative permeabilities to water deviate from those derived by coreflood simulation in the low water saturation region. In addition to simulating a coreflood experiment using in-situ saturation monitoring, especially for heterogeneous rock, pore-scale modeling can be used to predict relative permeabilities and capillary pressure with more physical sense. The combination of pore and core-scale analysis improves the understanding of flow through heterogeneous porous media and the method bridges pore to core-scale analyses.

The proposed method to bridge pore and core-scale analyses gives reasonable results; however, a slight deviation can be seen in the figures because the modified network from the reference with the inferred wettability is used to model the two-phase flow process. To increase the predictive capability of the pore-scale model, it is better to generate more representative networks using a two-step approach rather than modifying the reference network. In addition wettability should be measured directly for each pore-type.

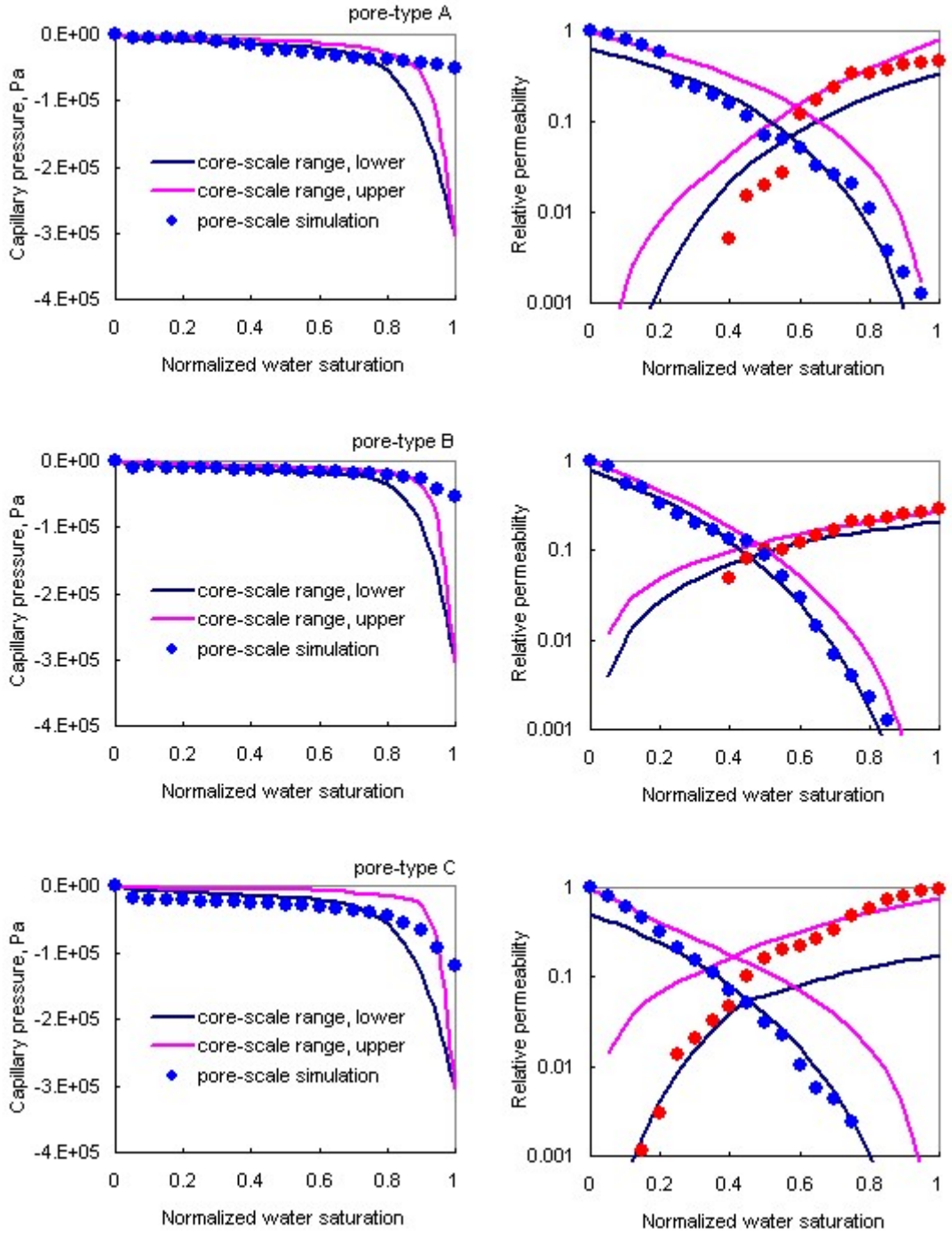

Figure 5. Capillary pressure and relative permeabilities predicted for different pore-types using pore-scale modeling are compared with those derived from core-scale simulation using the Genetic Algorithm. The range of curves that match the coreflood experiment is shown by two lines, which are the upper and lower bounds.

CONCLUSIONS AND FUTURE WORK

The methodology to bridge pore and core-scale analyses was proposed as shown by the workflow in Figure 6. Coreflood experiments were carried out to estimate flow properties such as relative permeabilities and capillary pressure. In-situ saturation monitoring was necessary for detailed analysis and core-scale characterization. To reproduce coreflood experiments, coreflood simulation models were used to determine flow properties at the core-scale. Petrographical and petrophysical analyses were used to determine key pore-types in the core. An effective optimization process was necessary to reproduce the coreflood experiments by simulation; therefore, an automated history-matching program using the Genetic Algorithm was used to interpret coreflood displacements on the heterogeneous carbonate cores. The program successfully predicted a reasonable set of relative permeabilities and capillary pressure within given pore-types. The predicted flow properties were numerical solutions of coreflood simulations; therefore, pore-scale modeling was used to support these flow properties derived at the core-scale. The networks modified from the reference structure using the mercury injection capillary pressure and the permeabilities were used as the inputs for pore-scale modeling to predict flow properties. In addition to the mercury injection, NMR has also been used to generate networks [25, 26]. The wettability in the network was assumed using available information. Although the wettability might not be representative, relative permeabilities and capillary pressure predicted by the pore-scale modeling were consistent with those derived by the coreflood simulation using the Genetic Algorithm. The combination of pore and core-scale analyses improves the understanding of flow through heterogeneous porous media and the method bridges pore to core-scale analyses.

Future work will be devoted to increase the predictive capability of pore-scale modeling in order to bridge pore to core-scale analyses. It is better to use more representative networks than those modified from a reference based on Berea sandstone. New methods to capture sub-micron pore structures are currently investigated to obtain pore space images. Then more appropriate networks can be extracted from the voxel representations. The bulk wettability of the specific pore-types is necessary to predict flow behavior.

ACKNOWLEDGEMENTS

The author would like to acknowledge JOGMEC for granting permission to publish this paper and his colleagues especially for Noriyuki Tokuda and Shunya Takahashi. He thanks Per Valvatne (Shell) for providing his pore-scale network code and Pål-Eric Øren (Statoil) for sharing the Berea network. He is also grateful to Martin Blunt and his colleagues of the pore-scale modeling group at the Imperial College London for their advice.

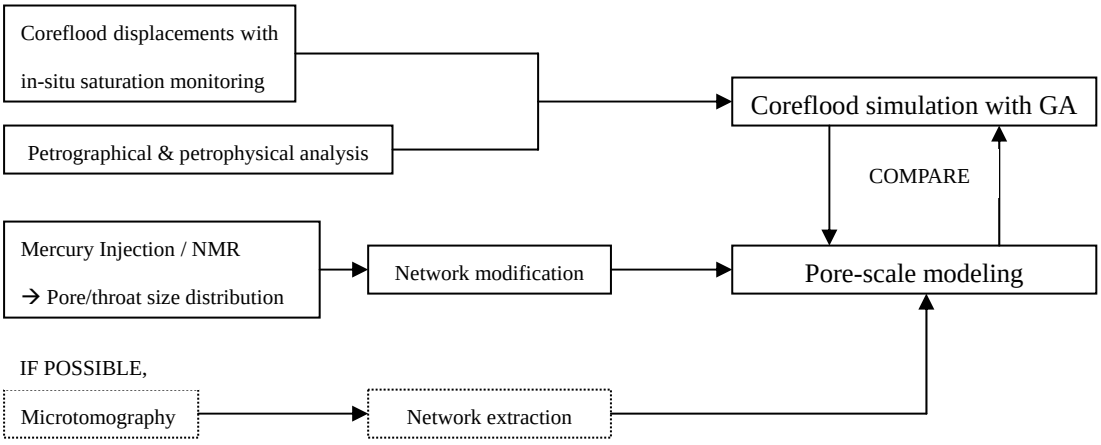

Figure 6. The proposed workflow to bridge pore and core-scale analyses of flow properties

REFERENCES

1. Honarpour, M., L. Koederitz, and A.H. Harvey, *Relative Permeability of Petroleum Reservoirs*, CRC Press, Inc., (1986).
2. Dullien, F.A.L., *Porous Media: Fluid Transport and Pore Structure*, Academic Press, San Diego, (1992).
3. Christie, M.A., Flow in porous media - scale up of multiphase flow. *Current Opinion in Colloid & Interface Science*, (2001) **6**, 3, 236-241.
4. Takahashi, S., N. Tokuda, and T. Nakashima, Upscaling method of relative permeability from plug core to whole core. *International Symposium of the Society of Core Analysts*, (2004) SCA2004-16.
5. Oshita, T. and H. Okabe, Early water breakthrough in carbonate core samples visualized with X-ray CT. *International Symposium of the Society of Core Analysts*, (2000) SCA2000-08.
6. Sen, M.K., A. Dattagupta, P.L. Stoffa, L.W. Lake, and G.A. Pope, Stochastic Reservoir Modeling Using Simulated Annealing and Genetic Algorithms. *SPE Formation Evaluation*, (1995) **10**, 1, 49-55.
7. Romero, C.E. and J.N. Carter, Using genetic algorithms for reservoir characterisation. *Journal of Petroleum Science and Engineering*, (2001) **31**, 2-4, 113-123.
8. Velez-Langs, O., Genetic algorithms in oil industry: An overview. *Journal of Petroleum Science and Engineering*, (2005) **47**, 1-2, 15-22.
9. Tokuda, N. and S. Takahashi, Development of automated history-matching program base on genetic algorithm for X-ray CT core flooding experiment. *International Symposium of the Society of Core Analysts*, (2004) SCA2004-14.
10. Blunt, M.J., M.D. Jackson, M. Piri, and P.H. Valvatne, Detailed physics, predictive capabilities and macroscopic consequences for pore-network models of multiphase flow. *Advances in Water Resources*, (2002) **25**, 8-12, 1069-1089.
11. Laroche, C. and O. Vizika, Two-phase flow properties prediction from small-scale

data using pore-network modeling. *Transport in Porous Media*, (2005) **61**, 1, 77-91.
12. Dunsmuir, J.H., S.R. Ferguson, K.L. D'Amico, and J.P. Stokes, X-ray microtomography. A new tool for the characterization of porous media. *Paper SPE22860 proceedings of SPE Annual Technical Conference and Exhibition held in Dallas, Texas, October 6-9, 1991*, (1991) 423-430.
13. Knackstedt, M.A., C.H. Arns, A. Limaye, C.H. Arns, A. Limaye, A. Sakellariou, T.J. Senden, A.R. Sheppard, R.M. Sok, W.V. Pinczewski, and G.F. Bunn, Digital core laboratory: Reservoir-core properties derived from 3D images. *Journal of Petroleum Technology*, (2004) **56**, 5, 66-68.
14. Quiblier, J.A., A New Three-Dimensional Modeling Technique for Studying Porous-Media. *Journal of Colloid and Interface Science*, (1984) **98**, 1, 84-102.
15. Adler, P.M., C.G. Jacquin, and J.A. Quiblier, Flow in Simulated Porous-Media. *International Journal of Multiphase Flow*, (1990) **16**, 4, 691-712.
16. Okabe, H. and M.J. Blunt, Prediction of permeability for porous media reconstructed using multiple-point statistics. *Physical Review E*, (2004) **70**, 6, art. no.-066135.
17. Bryant, S. and M. Blunt, Prediction of Relative Permeability in Simple Porous-Media. *Physical Review A*, (1992) **46**, 4, 2004-2011.
18. Bakke, S. and P.E. Oren, 3-D pore-scale modelling of sandstones and flow simulations in the pore networks. *SPE Journal*, (1997) **2**, 2, 136-149.
19. Pilotti, M., Reconstruction of clastic porous media. *Transport in Porous Media*, (2000) **41**, 3, 359-364.
20. Lucia, F.J., *Carbonate reservoir characterization*, Springer, Berlin, Germany, (1999).
21. Lindquist, W.B. and A. Venkatarangan, Investigating 3D geometry of porous media from high resolution images. *Physics and Chemistry of the Earth, Part A: Solid Earth and Geodesy*, (1999) **24**, 7, 593-599.
22. Delerue, J.F. and E. Perrier, DXSoil, a library for 3D image analysis in soil science. *Computers & Geosciences*, (2002) **28**, 9, 1041-1050.
23. Silin, D.B., G. Jin, and T.W. Patzek, Robust determination of the pore space morphology in sedimentary rocks. *Paper SPE84296 proceedings of the SPE Annual Technical Conference and Exhibition held in Denver, Colorado, U.S.A., 5-8 October 2003*, (2003).
24. Valvatne, P.H. and M.J. Blunt, Predictive pore-scale modeling of two-phase flow in mixed-wet media. *Water Resources Research*, (2004) **40**, W07406, doi:10.1029/2003WR002627, 2004.
25. Moctezuma-Berthier, A., S. Bekri, C. Laroche, and O. Vizika, A dual network model for relative permeability of bimodal rocks: application in a vuggy carbonate. *International Symposium of the Society of Core Analysts*, (2003) SCA2003-12.
26. Valvatne, P.H., X.D. Jing, and R.M.M. Smits, Modeling pore geometric and wettability trends of multiphase flow in porous media. *International Symposium of the Society of Core Analysts*, (2004) SCA2004-16.