

CHARACTERIZATION OF BITUMEN BEARING CARBONATE ROCKS

J. Bryan, J. Wang and A. Kantzas
University of Calgary, TIPM Laboratory

This paper was prepared for presentation at the International Symposium of the Society of Core Analysts held in Noordwijk, The Netherlands 27-30 September, 2009

ABSTRACT

Several countries, including Canada, contain sizeable bitumen resources in highly fractured carbonate rocks. Any possible recovery of bitumen from these reservoirs will be highly dependent on proper understanding of the rock and fluid properties and how they vary in the reservoir. These carbonates are extremely heterogeneous, and as a result proper reservoir characterization is challenging. In this study, a combined approach of x-ray computer tomography and low field NMR were applied on two full diameter native-state cores. CT imaging provides 3-D density and porosity, and maps a detailed distribution of the fracture network and primary, secondary or karst (breccia) porosity, as it varies for different rock types and locations. NMR spectra were acquired along the length of each core, in order to provide water and bitumen saturation predictions, and information about the fluid's locations in the rock. By combining the CT and NMR results, additional information regarding the fluid saturations and oil viscosity can also be identified. This study demonstrates how the application of CT and NMR technology can be used simultaneously for improved reservoir characterization in complex bitumen-carbonate systems. These techniques could also be extended to interpreting logging tool data acquired in such formations.

INTRODUCTION

Considerable worldwide oil resources are located in carbonate reservoirs. These formations pose unique challenges to oil recovery, due to factors such as partial/full oil wetting and heterogeneity of pore structures. In Canada, the focus in recent years has shifted to the development of the high density and viscosity bitumen that is found mainly in the oil sands of northern Alberta. Approximately 71 billion m³, or 26% of the total bitumen resource base, is located in carbonate reservoirs [1]. These carbonates are difficult to exploit due to their complex geology, and are characterized by heterogeneous porous media exhibiting low primary recovery, rapid pressure decline and significant production challenges [2]. The in-place oil viscosity is also exceedingly high, on the order of millions of mPa·s (cP) at reservoir temperature.

The screening of any potential EOR technique first requires a good understanding of how the fluid and rock properties vary in the reservoir. In this study, a combination of x-ray CT scanning and low field nuclear magnetic resonance (NMR) are used to characterize the rock properties and the fluid saturations/distributions in two samples of carbonate from northern Alberta. NMR and density measurements are common in both special core analysis and in logging tool runs, so the successful application of these techniques to bitumen carbonate reservoir characterization can be very useful for future field development.

CT CHARACTERIZATION OF CARBONATES

In this study, two carbonate samples were chosen from fields in northern Alberta. The physical properties of these cores are shown in Table 1. Core 1 is a vuggy dolomite, while Core 2 has a dolomite mudstone structure. Example CT scans are shown in Figure 1. Core 1 contains a relatively dense rock matrix, as evidenced by its dark colour, and there are light (low density) vugs interspersed in the rock. In contrast, Core 2 has a lower overall density, with some additional fractures present.

These cores were both saturated with unknown amounts of bitumen and water, thus the fluid density can be approximated as being 1000 kg/m³. Using the same assumed grain density for dolomite (2870 kg/m³), the lower CT density values would be indicative of higher total porosity. Accordingly, the measured porosity values are higher in Core 2. Table 2 compares the CT and gas expansion porosity values, showing that the CT estimates of porosity are relatively accurate. The value of obtaining CT data is that initial characterization could be performed on native-state sections of core containing bitumen and water, so the core does not need to be cleaned in order to evaluate its porosity. In addition, CT measurements could potentially be taken of long sections of drilled core, thus providing a high-resolution density map against which the log density values can be calibrated.

Aside from providing an overall measure of the core density and porosity, CT imaging of the core at its initial state can also be used to provide a distribution of the density in each cross section. Figure 2 compares the density histograms for a single cross-section in both cores. The mean densities in Core 2 are lower than in Core 1, but the distribution of densities is also different in these cores. It is expected that for an infinite number of pores, the random distribution of matrix porosity could be expected to follow a normal distribution [3]. The high-density peak, representing the intra-matrix porosity (i.e. porosity between grains or crystals), was fitted with to a Gaussian curve. The inter-matrix, or open porosity (i.e. the porosity from vugs and fractures), was taken as the low-density region that exists below three standard deviations from the mean of the Gaussian. Accordingly, the fraction of pixels that are considered as “matrix porosity” vs. “open porosity” could be de-convoluted.

These calculations were performed on the cores containing native-state fluids, but it can be shown that the matrix vs. open porosity distributions will also be similar in dry cores. The mean porosities were calculated for the matrix and open density fractions of the core. Figure 3 shows that the matrix porosity is significantly higher in Core 2 than in Core 1: 25% compared to 12%, which is expected from the CT images. The calculated value of open porosity was similar for both cores: 42% and 48% for cores 1 and 2, respectively. Therefore, Core 2 has both a higher overall porosity and also higher mean values of matrix and open porosity. Despite this fact, the permeability of this core is lower than that of Core 1. This discrepancy is reconciled by considering the fraction of pixels that fall within the range of open porosity, which is plotted in Figure 4. Despite the higher overall porosity of Core 2, the fraction of pixels that fall within the range of open porosity (i.e. density < three times the standard deviation from the mean of the Gaussian peak) is much lower in this core. On average, 21% of the density pixels fall into the open porosity range in Core 1, compared to only 7% in Core 2. This illustrates that the high permeability pathways are strongly related to the open porosity (vugs and fractures) in the system, so long as this porosity is connected. This means that as long

as steam or solvent is able to displace oil out of the matrix and into the open porosity, oil will drain more easily in Core 1 than in Core 2.

The total porosity (ϕ_{TOT}) is the summation of the matrix and open porosity fractions:

$$\phi_{TOT} = f_{op}\phi_{op} + (1 - f_{op})\phi_m \quad (1)$$

Where, ϕ_{op} and ϕ_m are the average porosity values of the open space and matrix densities. The parameter f_{op} is the fraction of pixels that fall within the open porosity, shown in Figure 4. The open porosity pore space is therefore ($f_{op}\phi_{op}$). This product is 48% of the total porosity in Core 1, compared to only 12% of the total porosity in Core 2. Therefore, the description of the core pore space in terms of open vs. matrix porosity not only provides an indication of the permeability of the porous medium, but also the fraction of the pore fluids that reside in these high mobility pathways. In Core 1, therefore, a significant fraction of the pore space lies within the porous open porosity fraction for this core, so it will likely respond better to recovery processes. The one question that cannot be answered through CT analysis of densities is whether this open porosity contains bitumen or water; this must be addressed through NMR.

NMR CHARACTERIZATION OF CARBONATES

It is a well-referenced fact that NMR distributions of water-saturated cores are essentially analogous to pore-size distributions [4, 5]. Figure 5 shows the spectra of Cores 1 and 2, saturated with water. These spectra were obtained after the cores had been cleaned and re-saturated. The cores were longer than the region of magnetic field homogeneity in the NMR, so in order to quantify the spectra a sample of water (porosity = 1) was first run, and NMR amplitudes were converted into porosity units:

$$\phi_w = \frac{A_w}{A_{p1}} \quad (2)$$

A_w is the amplitude of water in the core, and A_{p1} is the amplitude that would be obtained for a porosity of unity. The term ϕ_w is the porosity units of water in the core.

It is evident that Core 2 contains a higher porosity than Core 1, which had also previously been observed. Table 2 compares the NMR porosity estimates made from these water-saturated spectra against the CT and core analysis porosity, and all the measurements yield similar results. Of more consequence, however, is the distribution of the water signal in both cores. Core 1 contains a wider distribution of larger pores, and thus would be expected to have a higher permeability. Accordingly, the mean water relaxation times are 268 ms and 35 ms for Cores 1 and 2. Once again, although Core 2 has a higher porosity, the water T_{2gm} values clearly indicated that the permeability will be expected to be higher in Core 1.

The question that must be answered, however, is whether this result would also be evident in measurements of native state cores. This is examined in Figure 6, which compares the spectra of the cores containing initial oil and water. In cores containing viscous bitumen, the oil relaxes quickly due to bulk relaxation, and information regarding where the oil is located in the porous media is lost. However, the signal from

residual water can still be interpreted against the water-saturated spectra, to identify where the fluids are located [6]. A portion of the water amplitude at the longer relaxation times has disappeared, indicating that oil exists at least partially in these pores. However, even in relatively homogenous media some water will be by-passed, and this will be even more evident in heterogeneous carbonate systems. The fact that Core 1 still shows a wider distribution of water T_2 signal compared to Core 2 is suggestive of the system of larger pores that is present in this core.

From the spectra in Figure 6, the water amplitude was taken to be the signal after the first peak. The mean water relaxation times are 85 ms for Core 1, and 14 ms for Core 2. Once again, Core 1 has higher water T_{2gm} values, so it could still be inferred from the native state spectra that the mean pore sizes are larger in Core 1, and that permeability should be higher in this core. However, due to the oil displacing water out of some of the highest permeability pathways, the water T_{2gm} values are different between the cores fully saturated with water and the initial state cores. Thus, permeability models that were developed on cores containing only water will not be directly applicable in bitumen carbonate systems.

Finally, if the CT porosity is known, the NMR water saturation can be calculated by dividing the NMR water porosity units by the total porosity. These results are summarized in Table 3, with oil saturation found by difference. The conversion of oil porosity units into actual volumes requires knowledge of the oil relative amplitude index, which is not a constant in different bitumen samples [7]. Thus, the assumption made is that there is no gas in the core, so the entire pore space is full of bitumen and water. In reservoir logging of bitumen carbonate systems, this assumption will be valid so NMR is able to provide both a measure of pore size distribution and fluid saturations in carbonate cores.

OVERALL DISCUSSION AND IMPLICATIONS

The characterization of porosity distributions alone for determining permeability in carbonates can be misleading, unless an attempt is made to separate matrix vs. open porosity. This approach can also be augmented through low field NMR spectra, which can be used to predict the distribution of pore sizes present, based on the water relaxation times. Finally, the initial water saturation can be calculated by comparing NMR water porosity units to the total CT porosity. In this manner, measurements of initial oil and water saturations can be made even for zones that were altered due to the invasion of fresh water drilling mud, where resistivity data may not be valid. The combination of density and NMR measurements can provide significant information about the rock properties and fluid saturations in carbonate reservoirs and with proper tuning these measurements could also be made in field logging tools. Thus, improved reservoir characterization is possible in carbonates, and this has direct value to the proper design of field recovery strategies.

ACKNOWLEDGEMENTS

The authors wish to acknowledge the contributions from the staff of TIPM Laboratory, especially Mark Bennett, Sergey Kruchkov, Jun Gao and Lucy Liu. The core samples for this study were generously provided by Laricina Energy Ltd. Financial support for this project was received from the Canada Research Chair in Energy and Imaging with its Industrial Affiliates (Shell, Nexen, Devon, PetroCanada, Canadian Natural, ET

Energy, Suncor, Schlumberger, CMG Foundation, Laricina, ConocoPhillips and Paramount).

REFERENCES

1. Energy Resources Conservation Board, “Alberta’s Energy Reserves 2007 and Supply/Demand Outlook 2008-2017”, ST98-2008, F. Rahnama, Coordinator, June 2008.
2. Alvarez, J.M., Sawatzky, R.P., Forster, L.M. and Coates, R.M., “Alberta’s Bitumen Carbonate Reservoirs – Moving Forward with Advanced R&D”, 2008 World Heavy Oil Conference, Edmonton, AB Canada, Mar 10 – 12, 2008.
3. Walpole, R.E. and Myers, R.H., Probability and Statistics for Engineers and Scientists, 4th Edition, Macmillan Publishing Company, New York, NY USA, 1989.
4. Straley, C., Rossini, D., Vinegar, H., Tutunjian, P., and Morriss, C., “Core Analysis by Low Field NMR”, SCA 9404, 1994 International Symposium of the Society of Core Analysts, Stavenger, Norway, Sept 12 – 14, 1994.
5. Coates, G., Xiao, L. and Prammer, M., *NMR Logging Principles and Applications*, Halliburton Energy Services, 1999.
6. Bryan, J., Mai, A. and Kantzas, A., “Investigation into the Processes Responsible for Heavy Oil Recovery by Alkali-Surfactant Flooding”, SPE 113993, 2008 SPE Improved Oil Recovery Conference, Tulsa, OK USA, Apr 19 – 23, 2008.
7. Kantzas, A., Bryan, J., Mai, A. and Hum, F., “Low Field NMR Applications in Oil Sands Mining and Extraction”, SCA 2005-23, International Symposium of the Society of Core Analysts, Toronto, Canada, Aug 21 – 25, 2005.

Table 1: Physical Properties of Cores 1 and 2

Core ID	Description	Porosity (fraction)	Air perm (mD)	Brine perm (mD)
1	Vuggy dolomite	0.161	86.7	47.1
2	Dolomite mudstone	0.270	32.9	21.6

Table 2: Measurements of Porosity by Various Techniques

Core ID	NMR Porosity	CT Porosity	Core Analysis Porosity
1	0.152	0.19	0.161
2	0.246	0.27	0.270

Table 3: NMR Estimates of Initial Oil and Water Saturation

Core ID	CT Porosity	Water P.U.	S_{wi}	Init S_o
1	0.19	0.0258	0.139	0.861
2	0.27	0.0560	0.206	0.794

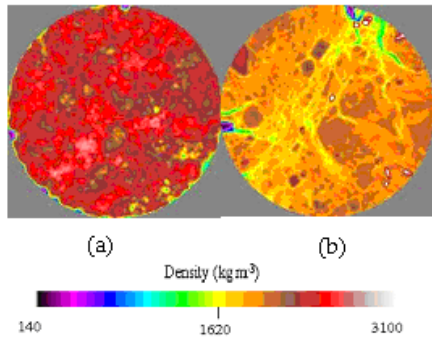


Figure 1. Example CT axial images of Core 1 (a) and Core 2 (b)

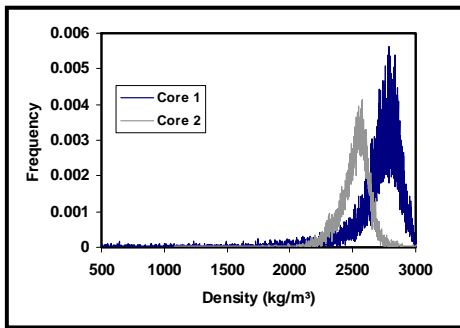


Figure 2: Density histograms for carbonate samples 1 and 2

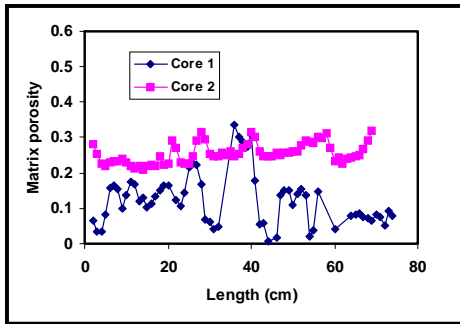


Figure 3: Matrix porosity distribution for samples 1 and 2

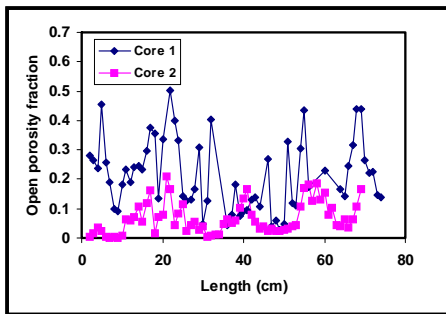


Figure 4: Fraction of open porosity for samples 1 and 2

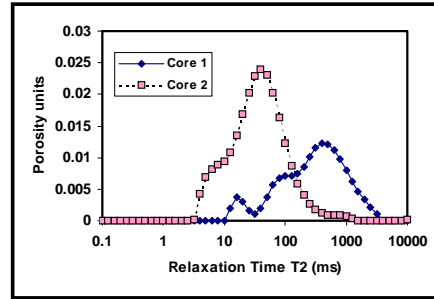


Figure 5: Spectra of samples 1 and 2, saturated with water

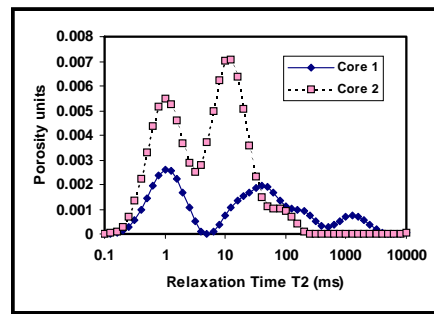


Figure 6: Spectra of samples 1 and 2 in their initial state