PETROPHYSICS AND RESERVOIR CHARACTERISTICS

P. Macini and E. Mesini

Department of Chemical, Petroleum, Mining and Environmental Engineering, University of Bologna, 40131 Italy

Keywords: Porosity, permeability, saturation, wettability, relative permeability, interfacial tension, capillary pressure, fractional flow, laboratory measurements, petrophysics, coring, core analysis, well logging, hydrocarbon reservoir, reservoir model, permeameter, porosimeter, extractor, saturation cell, porous media

Contents

Summary

Petrophysics is the science dealing with the fundamental chemical and physical properties of porous media, and in particular of reservoir rocks and their contained fluids. These include storage and flow properties (porosity, permeability and fractional flow), fluid identification, fluid phase distribution within gross void space (saturation), interactions of surface forces existing between the rock and the contained fluids (capillary pressure), measurements of pressure, stress conditions, electrical conductivity of fluid-saturated rocks, *etc*. These properties and their relationships are used to recognize and assess hydrocarbon reservoirs, source rocks, cap rocks, and aquifers.

Petrophysical properties form a set of essential engineering parameters and still remain the basic tools to obtain reliable information by which reservoir rocks may be described quantitatively, in order to assist petroleum engineers in the evaluation of hydrocarbon reserves and for planning well completion and optimize production operations during

the reservoir life.

The specific focus of this chapter is aimed to define and discuss the most important petrophysical properties of reservoir rocks, to describe the experimental methods and tools for their direct laboratory measurement on cores (with some references to indirect measurements, mainly performed by well logging) and finally to evaluate to what extent direct and indirect measurement can be integrated and applied to the reservoir management.

Measurement integration is extremely important, since direct measurements performed on cores are carried out in laboratory conditions, which are usually very different, compared to the reservoir conditions.

The early science of core analysis was basically an art, a qualitative issue of odors and tastes, sucking on the rock and visual examination. From such early beginnings this art evolved into a proper science, using the latest developments in experimental methods of physical and chemical analyses as they became available. Today, mass spectrometry, gas chromatography, electron microscopy, high-frequency phase analysis, acoustic wave analysis, and nuclear magnetic relaxation analysis are among the tools being used in the more sophisticated core testing.

1. Laboratory Samples Preparation

A critical issue in utilizing laboratory measurements is the representativeness of the sample under investigation, *i.e.*, to what extent the results of lab data can be extended to characterize large underground rock volumes, or to determine their actual value at a level of certainty needed to make economic decisions leading to reservoir development and production. In dealing with petrophysical properties, it is crucial to define the investigation scale, which spans from a small scale (a single core, a well or a group of wells) to a single reservoir up to a regional geological scale.

Direct core measurements only grant information on a small scale, and can be extended to a larger scale by the aid of properly integrated and calibrated indirect measurements and taking into account the possible heterogeneity and discontinuity of the reservoir by means of geostatistical methods. In general, the most difficult part of any petrophysical measurement is to determine the actual values at a level of certainty needed for making economic decisions regarding the possible development or the production management of hydrocarbon reservoir.

Strictly speaking, as far as laboratory practices are concerned, all measurements must be made on samples (or sub-samples prepared in the same lab) whose volume must be no smaller than the Representative Elementary Volume (REV). REV is defined as the minimum bulk volume of porous medium that can be considered continuous; in this volume the definitions of the petrophysical properties are statistically representative and are physically defined.

Let us consider, for example, coarse gravel and fine sandstone: it is obvious that the REV of gravel is larger than that of sandstone. As a rule of the thumb, linear sample

size must not be smaller than 50 times the average grain size of the sample. Concerning permeability, the situation is even more complex due to the possible influence of fractures or discontinuities present at different scales (sometimes exceeding the size of a lab sample), and the presence of clay interbeddings.

Though negligible in volumetric terms, the above features may have a considerable impact on permeability estimates (definitely true as far as the sample is concerned), but that can vary up to several orders of magnitude at *in situ* conditions.

Laboratory measurements are made on rock samples usually cut from cores obtained from subsurface formations by either rotary, sidewall or cable-tool coring (even though several techniques of quantitative analysis are developing that are carried on drilling cuttings).

All the above coring techniques may alter or damage the samples in many ways. Two phenomena occur during coring that may significantly alter the saturation values: the invasion of mud filtrate, the expansion and or the phase change of the formation fluids (e.g. the gas dissolved in crude oil may reach the bubble point and separate as a distinct phase within the pore space).

As the core is brought to the surface and the external pressure is reduced, the expansion of free gas or dissolved gas expels both oil and water from the core, eventually producing a fluid saturation (water, oil and gas) different than the one in reservoir conditions.

The phenomenon is even more complex when considering the effects of mud filtrate invasion, due to the differential pressure between the mud column and the formation fluids that may displace these latter.

The fluid content of a core subject to the above phenomena (very likely to happen if a standard coring technique is used) is called "residual fluid saturation". Today, special coring techniques exist, which maintain the original pressure of the cores and collect any formation fluid leached during tripping out.

Damages due to mud filtrate invasion also depend on the type of drilling mud; water-based mud causes an increase in water saturation, whereas oil-based mud causes lesser alterations in oil-saturated samples.

The size and form of samples used in laboratory vary from drilling cuttings, loose sands and coarse pieces of consolidated rocks up to samples of regular geometrical shape. The most commonly used form is the cylinder, and less frequently the cube or parallelepiped. The cylindrical samples (also known as core plugs) are cut from the full diameter cores (about 10 cm in diameter) sampled and recovered from the well (Figure 1).

Upon the full diameter (or full size) core has been delivered at the laboratory, core plugs are cut with a diameter of 2 to 3 cm at 15 to 30 cm intervals along each core. Thus, a core plug represents a sub-sample of the core volume about 100 to 150 times smaller

than the original one, whose effects on REV must be taken into account.

Figure 1. Full diameter core (left) and core plugs (right) cut for laboratory measurements. Cores can be full diameter cores (that is, they are nearly as large in diameter as the drill bit) taken at the time of drilling, or sidewall cores, generally less than 1 inch (2.54 cm) in diameter, taken after a hole has been drilled. Core plugs are cut from full diameter cores.

If the full size core is made up of consolidated rock, the core plugs are cut using a diamond rotary coring bit. During cutting, the core plug must be carefully cooled with a forced fluid circulation, in order to avoid problems related to the thermal degradation of minerals. Normally, a first set of core plugs are cut parallel to the axis of the core and a second one is cut perpendicular to the core axis and, when possible, parallel to the formation layering. If the full core contains weakly cemented or unconsolidated shaly formations, the core plugs may also be cut using a plunge cutter slowly pushed in the core and removed.

Preparation, handling and measurements on core plugs of fragile, poorly cemented or loose formations are problems that have not been yet fully addressed. Damages to which these materials can be subjected during coring operation and lab sample preparation may be so severe to reduce the reliability of these data. In some cases, especially in loose formations, it may be preferable to reconstruct the sample in laboratory accordingly to standard procedures. In the best case, measurements obtained from these samples can only supply the order of magnitude of the investigated petrophysical property, and not its actual value at reservoir conditions.

Normally, the cores taken from reservoir rocks contain formation fluids, usually salt water (brine), sometimes accompanied by liquid or gaseous hydrocarbons, which must be completely removed before performing a number of laboratory measurements. To

clean the core plugs, special closed loop solvent extractors are used to remove the residual fluids, oil and water (see fluid extraction in the following section). After cleaning, the samples must be dried in a thermostatic oven to remove the solvent or to evaporate the water. Normally, the drying temperature is 105°C, *i.e.*, below the decomposition temperature of minerals containing crystallization water, but if clays are present, it must not exceed 60 °C.

There are numerous pitfalls to perform the above operations. Cleaning the core of crude and brine must be both careful and gentle. All the heavy fractions of the crude (normally asphaltenes) must be removed, but minerals composing the rock grains must not be damaged. Crystals of NaCl left from the original brine when the water is removed must also be removed, but the clay minerals must not be removed or disturbed. Gypsum, when present, must not be dehydrated during laboratory measurements, and hydroxyl water of clay minerals must not be removed and counted as part of the pore space. Finally, additional pore space must not be created during the cleaning process by flowing large volumes of fluid through samples with soluble minerals, such as gypsum, anhydrite, halite or limestone.

2. Fluid Saturation

In porous media, fluid saturation is defined as the fraction of the pore volume occupied by a given fluid. In general, the saturation S_i of the *i*-th fluid phase is defined as:

$$S_i = \frac{V_i}{V_p} \qquad (1)$$

$$\sum_i S_i = 1 \qquad (2)$$

where: V_i = volume of the *i*-th fluid phase, V_p = pore volume. Equation (2) is the continuity condition. If three immiscible phases are present, for example, gas, oil and water, the saturation of each phase is expressed by the following:

$$S_g = \frac{V_g}{V_p}, \qquad S_o = \frac{V_o}{V_p}, \qquad S_w = \frac{V_w}{V_p} \qquad (3)$$

$$S_g + S_o + S_w = 1 \qquad (4)$$

Where: S_g = gas saturation, S_o = oil saturation, S_w = water saturation, V_g = gas volume, V_o = oil volume, V_w = water volume. The spatial distribution of the fluids within the pores depends on numerous factors, including the physical properties of the reservoir fluids, as well as the interactions and the affinity between rock and fluids, a property known as wettability (see next section).The estimation of the saturation of reservoir rock is essential to calculate the volume of hydrocarbons in place, as well as to study the fluid flow within the reservoir, useful to evaluate the productivity index and the final recovery.

The study of saturation distribution is fairly complex, and subject to a considerable degree of uncertainty. Like other measurements performed on porous media, the saturation of the various phases may be determined either directly, by measuring V_g, V_o and V_w of a cored sample (in this case only residual liquids are measured, if the core has not been preserved carefully), or indirectly through capillary pressure measurements or well logging. In general, the saturations in a core have been flushed by the mud filtrate and are not representative of the *in situ* reservoir conditions.

Only samples cored with oil-based mud and taken high in the oil column (where the relative permeability to water is negligible) have a value of water saturation at *in situ* reservoir conditions, after having performed the correction for dissolved gas losses and stress effect. In the case of oil-based mud filtrate invasion, water saturation will remain immobile if S_w is less than 50% and mild surfactants are used in the mud.

2.1. Laboratory Measurements

Fluid saturation was once determined by extracting the fluids from a cored sample by heat, *i.e.*, vaporizing the water and the oil in a retort and condensing the vapors in a small receiving vessel. The method has different disadvantages, as the oil, when heated to high temperatures, tends to crack and coke, and the crystallization water within the rock is removed as well. Another method to determine fluid saturation is by extraction with a solvent (pentane, toluene, xylene, *etc.*).

Laboratory devices, known as extractors (Dean-Stark or Sohxlet type, Figure 2), are closed vessels containing a liquid organic solvent (toluene, pentane, octane, xylene, acetone, carbon disulphide, *etc.*) that is heated to temperatures close to 100°C to leach out oil and water from the sample. These can be either immersed in the solvent or exposed to dripping condensed vapors.

In the Soxhlet extractor, the sample soaks in hot solvent that is periodically siphoned off, distilled and returned to the sample. The process continues until the siphoned-off solvent becomes clear. In the Soxhlet apparatus, the sample soaks in the solvent, while in the Dean-Stark apparatus, the solvent flows through the sample from top to bottom.

In Dean-Stark apparatus the extracted water is condensed and measured separately in a graduated receiving tube, while the oil volume is determined by the weight difference of the vessel before and after testing. Of course, the solvent used must neither damage nor alter the mineralogical and petrophysical properties of the sample. Another method of fluid extraction is by means of a centrifuge.

A solvent is injected into the centrifuge and because of the centrifugal force it is displaced through the sample. The outflow fluid is trapped and the quantity of water in the core is measured.

Figure 2. Laboratory extractors, Dean-Stark (right) and Sohxlet (center and left) type (Petrophysics labs, Department of Petroleum Engineering, University of Bologna, Italy).

2.2. Indirect measurements:

In petroleum engineering applications, saturation can be estimated by measuring the electrical resistivity of the rock, either on laboratory samples or by means of well logging. The electrical resistivity of porous media is regulated by formation water resistivity (R_w), by oil and or gas saturation (non-conductor fluids) and by a function of pore geometry. The resistivity of a fluid-saturated rock can be extremely high (up to several thousand Ωm, in low porosity rocks), but is never infinite. In clean formations (*i.e.*, formations without clay particles inside the pores) the relationship between rock resistivity and water saturation can be expressed with an empirical equation, proposed by G.E. Archie in 1942:

$$\left(S_w\right)^n = \frac{1}{I_R} \tag{5}$$

where I_R is the resistivity index, defined as follows:

$$I_R = \frac{R_t}{R_0} \tag{6}$$

being:

$$R_0 = FR_w = \frac{a}{\varphi^m} R_w \tag{7}$$

The previous equations can be rewritten in the general form used to calculate water saturation:

$$S_{\mathrm{w}} = \left(\frac{aR_{\mathrm{w}}}{\varphi^{m} R_{\mathrm{t}}} \right)^{\frac{1}{n}} \qquad (8)$$

where S_{w} = water saturation, R_{t} = formation resistivity (containing hydrocarbons and water with a saturation of S_{w}), R_{0} = resistivity of the same formation fully saturated with water of resistivity R_{w}, F = resistivity Formation Factor, φ = porosity, n = saturation exponent (to be determined experimentally and usually varying between 1.5 and 5), a = numerical coefficient depending on lithology and pore geometry, m = cementation exponent or tortuosity factor, dependent on the type of sediments, the degree of consolidation of the rock and the shape of the pores. The saturation exponent n depends on lithology and rock wettability; it expresses the effect on the resistivity of de-saturating the sample, or replacing water with a non-conductive fluid. The saturation exponent is usually measured in laboratory on core plugs by measuring the resistivity index (I_{R}) as a function of S_{w}. The coefficients a and m are as well determined experimentally. The coefficient a is close to 1 (but it may vary from 0.6 to 1), whereas the cementation exponent m is generally equal to 2 in sandstones (but it may vary from 1.4 to 3 or more in tight reservoirs). In clean consolidated water-wet sands, the saturation exponent n is generally close to 2. Thus, an approximate expression to calculate water saturation in clean water wet sands is the following, also known as the Archie equation:

$$S_{\mathrm{w}} = \sqrt{\frac{R_{0}}{R_{\mathrm{t}}}} = \sqrt{\frac{FR_{\mathrm{w}}}{R_{\mathrm{t}}}} = \sqrt{\frac{aR_{\mathrm{w}}}{\varphi^{m} R_{\mathrm{t}}}} \qquad (9)$$

Archie postulated that the formation factor was a constant independent of R_{w} and solely a function of pore geometry. It has since been shown that F is independent of R_{w} only for a certain class of petrophysically simple rocks (*e.g.*, clean sands). In rocks with conductive minerals, such as shaly sands, there is a more complex dependence, and the value of S_{w} calculated by the above equation is not correct. In this case, more complex saturation equations are applied (known as Indonesian, Waxman-Smits, Simandoux, Poupon, *etc.*), which require an estimate of clay and its resistivity, generally extrapolated using other types of logs. Nuclear Magnetic Resonance (NMR) is another logging method that can be applied to determine the invaded zone saturation.

Integration of log and core saturation measurements
The integration of saturation measurements is difficult, and no general rules can be applied. The accuracy of fluid extraction, capillary pressure and log measurements must be individually checked and cross-correlated, since they depend upon various factors that are difficult to control. Capillary pressure measurements must be standardized and referred to reservoir conditions. Fluid extraction is an estimate of irreducible water saturation if an oil-based mud was used and the sample was cored in a high oil saturation zone (*i.e.*, well above the water table). On the contrary, the measurement accounts for residual fluid saturation only.

-
-
-

TO ACCESS ALL THE **43 PAGES** OF THIS CHAPTER,
Visit: http://www.eolss.net/Eolss-sampleAllChapter.aspx

Bibliography

Anderson G. (1975). *Coring and Core Analysis Handbook*, 200 pp. Tulsa, OK, PennWell Publishing Company. [A complete handbook on laboratory procedures for core analysis and field coring practices].

Archie G.E. (1942). The electrical resistivity log as an aid in determining some reservoir characteristics. *AIME Trans.*, 146, 54 – 62. [A seminal work on quantitative petrophysical analyses by well logging].

Darcy H. (1856). *Les fontaines publiques de la ville de Dijon*, 647 pp. Paris, Dalmont. [The classic experiment on the flow of water through water-saturated sand filters. The experiment is described in an appendix entitled *Détermination des lois d'écoulement de l'eau à travers la sable*].

Dullien F.A.L. (1979). *Porous Media – Fluid Transport and Pore Structure*, 396 pp. New York, Academic Press. [A reference text on fluid transport and pore structure characteristics of porous media].

Honarpour M., Koederitz L., Harvey A.H. (1986). *Relative Permeability of Petroleum Reservoirs*, 143 pp. Boca Raton, Florida, CRC Press. [A reference text on relative permeability studies].

Tiab D., Donaldson E.C. (1996). *Petrophysics. Theory and Practice of Measuring Reservoir Rock and Fluid Transport Properties*, 706 pp. Houston, Gulf Publishing Company. [The most complete and updated text on petrophysical properties of reservoir rocks].

Cherici G.L. (1995). *Principles of Petroleum Reservoir Engineering*, 398 pp. + 419 pp. (2 Vol.), Berlin, Springer Verlag. [A modern and complete treatise on hydrocarbon reservoir engineering and integrated reservoir studies].

Muskat, Morris, *Physical principles of oil production*, New York, Wiley, 1949. [A seminal work that formalizes reservoir engineering and petrophysical measurements as a quantitative science].

Biographical Sketches

Paolo Macini is Associate Professor of Petroleum Engineering at the University of Bologna (Italy). Prof. Macini holds a M.S. Degree in Mining and Petroleum Engineering from the University of Bologna. He is a Registered Professional Engineer in Italy. Before joining the University, he worked for a Service Company supplying tools and services to the oil and gas industry, with experiences in Italy, North Sea, Africa and USA. He joined the University of Bologna in 1992, and his present appointment is Associate Professor at the Chemical, Mining and Environmental Engineering Department. Prof. Macini has taught a number of classes at the University of Bologna. Principal among them are Underground Fluid Mechanics, Drilling Engineering, Reservoir Engineering and Petroleum Production, which are also the main areas of his research activity. He has authored or co-authored more than 80 papers and three books. Prof. Macini is a member of the Society of Petroleum Engineers (SPE), where he served for more than 10 years in the Board of the Italian Section and as Chairman of the Ravenna Subsection, of the American Society of Mechanical Engineers (ASME), of the Russian Academy of Natural Sciences (US Section) and of the Italian Society of Mining Engineers (ANIM).

Ezio Mesini is Full Professor of Petroleum Engineering at the University of Bologna (Italy), and he holds a M.S. Degree in Mining and Petroleum Engineering from the same University. The main areas of his research activity are in the fields of Environment and energy, Subsidence phenomena due to underground fluid withdrawals, Laboratory investigations on porous media, Drilling and production technologies and

Well logging. He is author or co-author of more than one hundred papers and publications in the above topics

During his teaching activity at the University of Bologna, Prof. Mesini covered almost all the classes offered to Petroleum Engineering students at the College of Engineering.

He is member of the following scientific and professional associations: Italian Society of Mining Engineers (ANIM), Society of Petroleum Engineers (SPE), Pi Epsilon Tau (National Petroleum Engineering Honor Society, University of Southern California); International Hall of Fame (IHF Los Angeles); Russian Academy of Natural Sciences. In addition, he is member of the Editorial Board of the Journal of Petroleum Science and Engineering, Elsevier, Amsterdam.