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A new experimental method for measuring the three-phase relative permeability of oil, gas, and water

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ABSTRACT

For tertiary oil recovery, the gas drive is often implemented after water flooding. The three-phase flow phenomenon of oil, gas, and water exists during the process of gas injection. The three-phase relative permeability should be measured to further study the flow characteristics of oil, gas, and water in porous media. In this work, the steady-state flow method is adopted to establish a combined experimental method based on the principle of relationship between resistivity and water saturation, and the principle of on-line CT scanning is used to measure the three-phase relative permeability. The relative permeability of oil, gas, and water is measured under different saturation histories, including the water alternating gas flooding, in which water saturation decreases, oil saturation decreases, and gas saturation increases, as well as gas alternating water flooding, in which water saturation increases, oil saturation decreases, and gas saturation decreases. The experimental results show that in a water-wet core, the relative permeability of water is a function of its own saturation, and its isoperms are straight lines. The relative permeability of oil and gas phase is affected by their saturation and other phase saturations. In an oil-wet core, the isoperms of oil, water, and gas are convex to the point of 100% their own saturation, which means the relative permeability of oil, gas and water depend on all the three phase saturations. The saturation histories influence the isoperms of the three phases differently. Compared with the two-phase flow, the three-phase flow is more complex. This new experiment provides an approach and theory for the study of three-phase seepage laws in the gas drive.

1. Introduction

The relative permeability curve is one of the most important data source in the reservoir development. The data are applied to reservoir numerical stimulation, dynamic analysis, prediction and many other aspects. The gas drive process is often accompanied by the three-phase flow of oil, gas, and water. The three-phase flow under reservoir conditions is extremely complex. It is affected by the reservoir pressure and reservoir heterogeneity, as well as by the wettability of the reservoir and fluid distribution. Therefore, the two-phase relative permeability curves are usually utilized in the reservoir dynamic analysis instead of the three-phase relative permeability curves. This approach ignores the effect of the one-phase flow, which causes a large deviation with the actual three-phase flow in the porous media, given that the formulation and adjustment of oil and gas field development plan is based on the three-phase flow of oil, gas, and water. To study the flow characteristics of oil, gas, and water in porous media, the saturation and relative permeability of the three phases flow oil, gas, and water should be measured.

At present, the research methods of the three-phase seepage law can be divided into two categories, namely, mathematical modeling and physical experiment method. Corey et al. (1956) first proposed the empirical model to calculate the oil relative permeability in the three-phase flow. Stone (1970) proposed the Stone model I based on channel flow theory, he believed that the wetting phase occupied the small channel, the non-wetting phase occupied the large channel, and the intermediate phase was in the middle and separated the wetting and non-wetting phases. After three years, Stone (1973) developed a new model to calculate the oil relative permeability of the three-phase flow by using four sets of the two-phase relative permeability data, the method was called Stone model II. He defined the σ_w as the sum of the relative permeability of oil and water in the oil-water two-phase system

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and σ_g as the sum of the relative permeability of oil and gas in the oil-gas two-phase system. He pointed out that these functions belong to water and gas saturation. These two models have been widely used. Maini et al. (1989) proposed a revised formula of oil relative permeability to address the limitations of the revised Stone model I (Aziz and Settari, 1979). They believed that the relative permeability of oil and gas cannot be measured under the irreducible water saturation and that the max oil relative permeability of water displacing oil was not equal to the max oil relative permeability of gas displacing oil. The previous study suggested that using the mathematical models to calculate the three-phase relative permeability is more convenient and faster. However, the mathematical methods have excessive hypothesis, and the models are idealized. In addition, the mathematical methods can calculate only the three-phase relative permeability curves under the saturation history of water-saturation increase, oil-saturation decrease, and gas-saturation increase (IDD), and most of the mathematical models are suitable only for water-wet cores.

Physical simulation experiments have not been widely conducted in the oil field development. The main difficulty lies in the accurate determination of the three-phase saturation of oil, gas, and water. Saraf and Fatt (1967) adopted the nuclear magnetic resonance technology to measure the three-phase saturations and obtain the three-phase relative permeability. They found that the water relative permeability only depends on water saturation. However, the relative permeability of oil depends on oil and water saturations, whereas that of gas has no evident variation trend.Oak et al. (1990) used water-wet Berea sandstone to study the two-phase and three-phase relative permeability. Oil and water saturations were obtained by X-ray absorption method, and gas saturation was calculated by using the formula. In China, Zhou et al. (1991) adopted microwave-weight techniques to measure the fluid saturation of kerosene, distilled water, and air under steady-state condition. They added a similar core at the end of the test core to eliminate the end effect. The results showed that water isoperm is parallel to its equivalent saturation line, oil isoperm is concave to the 100% oil saturation point, and the gas isoperm is convex to the 100% gas saturation point. At the formation temperature, Zhao et al. (1995) adopted the steady-state method to measure the three-phase relative permeability of oil-wet and water-wet artificial sandstones under the IDD saturation history. Resistivity and weighing methods were used to calculate the oil saturation and water saturation, respectively. The results showed the significant effect of wettability on the relative permeability of water, oil, and gas. In the water-wet sandstones, the water isoperm is a set of straight lines, which indicates that the water relative permeability only depends on water saturation. However, the relative permeability of oil and gas depends on the saturation of all three phases. In the oil-wet sandstones, the three-phase relative permeability depends on the saturation of all three phases, and the isoperms of all three phases are convex toward 100% saturation points.

Although the physical simulation experiments are complicated and time-consuming, they can simulate the actual flow process in porous media and the three-phase flow laws of different saturating histories (Lv et al., 2012a; Shen et al., 2010). Therefore, the steady-state method was used based on the previous studies. The measurement approach based on the relationship between resistivity and water saturation and the theory of online CT scanning is established by introducing the Archie equation. Experiments were carried out in the different wettability cores and the different saturation histories to simulate the three-phase flow of oil, gas, and water in porous media and to determine the characteristics of the three-phase flow during the different development stage. This new method is precise in measuring the relative permeability of oil, gas, and water.

2. Experimental principle

2.1. Principle of resistivity measurement

Generally, the matrix of oil and gas reservoir is not conductive. A large concentration of brine in a rock results in low resistance value. So the resistivity in formation water is low and infinite in oil, large electrical differences exist between the two. Thus, rock electricity can mostly reflect a change in water saturation.

According to Archie's equation (1942), when the water saturation in a pure sandstone is less than 100%, which means there are other fluids (such as oil or gas) in the pores, its resistivity is directly proportional to the resistivity of the same sandstone 100% saturated water, the ratio coefficient is called the resistivity-increase coefficient. The equation is expressed as follow:

$$I_A = \frac{R_t}{R_o} = \frac{b}{S_w^n} = \frac{b}{(1-S_o)^n} \tag{1}$$

Where.

I_A is resistivity index; R_o is resistivity at a water saturation of 100%; R_t is resistivity of oil-bearing rock; S_w is water saturation; S_o is oil saturation; b is lithology factor; n is saturation exponent. b and n are only related to rock properties.

Therefore, by measuring the dynamic change in oil-bearing rock resistivity, the corresponding change in water saturation can be obtained (Li, 2011; Hu et al., 2015a). Given that water saturation at different places in the core is a single-valued function with resistance, water saturation values can be indirectly obtained by measuring the resistance value and then calibrating the relational expression between the resistance and water saturation.

2.2. Principle of online CT scanning

2.2.1. Fundamental principle

The X-ray beam is emitted from the X-ray tube in a CT instrument, which sweeps along a selected fault section of the experimental rock (as shown in Fig. 1). The number of X-rays that pass through the fault section is automatically measured by the CT instrument. After digital conversion, the absorption coefficient of per unit volume on the fault section can be automatically calculated. Then, the calculated absorption coefficient is composed of different digital matrices. These digital matrices can be transformed into a visual mathematical model by using the internal high-speed computer in the CT instrument. These matrices can be displayed or photographed on the computer. The X-ray attenuation coefficient of each pixel given in the image, which is the X-ray attenuation coefficient of per unit volume element, is usually converted into CT value (CTN) to using equation (2) (Lv et al., 2012b; Krevor et al., 2012). The relationship between the CT value (CTN) and the X-ray attenuation coefficient is as follows:

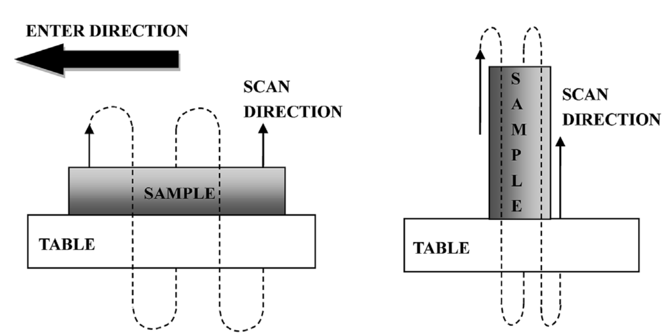

Fig. 1. Sketch map of core scanning direction.