

## Article

# Research on the Correction Method of the Capillary End Effect of the Relative Permeability Curve of the Steady State

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**Abstract:** Relative permeability curve is a key factor in describing the characteristics of multiphase flow in porous media. The steady-state method is an effective method to measure the relative permeability curve of oil and water. The capillary discontinuity at the end of the samples will cause the capillary end effect. The capillary end effect (CEE) affects the flow and retention of the fluid. If the experimental design and data interpretation fail to eliminate the impact of capillary end effects, the relative permeability curve may be wrong. This paper proposes a new stability factor method, which can quickly and accurately correct the relative permeability measured by the steady-state method. This method requires two steady-state experiments at the same proportion of injected liquid (wetting phase and non-wetting phase), and two groups of flow rates and pressure drop data are obtained. The pressure drop is corrected according to the new relationship between the pressure drop and the core length. This new relationship is summarized as a stability factor. Then the true relative permeability curve that is not affected by the capillary end effect can be obtained. The validity of the proposed method is verified against a wide range of experimental results. The results emphasize that the proposed method is effective, reliable, and accurate. The operation steps of the proposed method are simple and easy to apply.

**Keywords:** tight reservoir; capillary end effect; relative permeability curve



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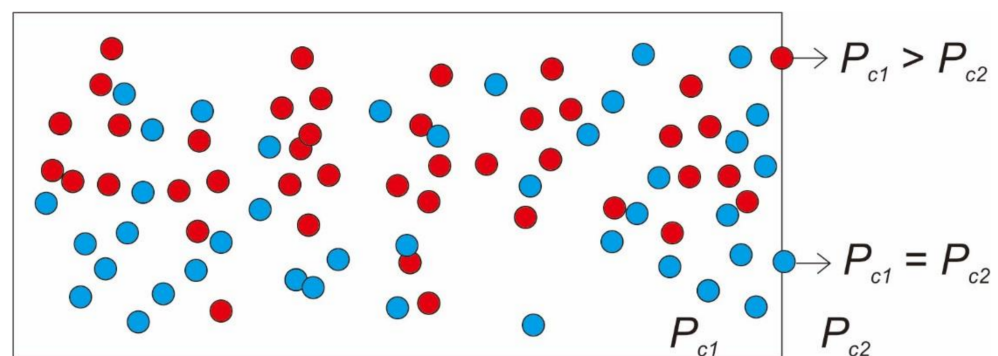
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## 1. Introduction

With the vigorous progress of tight oil and gas exploration and development, experts and scholars have continuously improved their understanding of tight reservoirs [1–4]. It is generally believed that tight reservoirs have small pores and throats, low permeability, and strong capillary forces [5,6]. The study of the mechanism of the fluids in porous media and influencing factors of tight reservoirs has important guiding significance for improving the recovery of this type of reservoir [7,8]. The relative permeability curve is the basic parameter for studying two-phase seepage in porous media and is an indispensable important data for tight oilfield development dynamic analysis, numerical simulation, and production forecasting [9–15].

The relative permeability data is usually obtained from the core displacement experiment of the tight reservoir in the laboratory. In the experiment, the end of the core is in contact with the outside which could be viewed as a medium with zero capillary pressure. The capillary pressure inside the core is greater than zero. The capillary force at the outlet

of the core disappeared. This discontinuity of capillary force is called the capillary end effect. Figure 1 is the physical schematic figure of the capillary end effect. In order to achieve capillary balance, the wetting phase will gather at the outlet end. This phenomenon continues until the saturation of the wetting phase reaches the saturation when the capillary force is zero. It will affect the saturation distribution of the wetting and non-wetting phases of the entire core, and will also affect the pressure drop across the entire core. Therefore, correcting the capillary end effect is very important for low-permeability reservoirs with strong capillary forces. Leverett [16] pointed out the existence of the capillary end effect as early as 1941. He showed that the capillary end effect makes the flow of oil and water more difficult. Osoba [17] pointed out the relative permeability curve will not be affected by the flow rate if there is no capillary end effect. If the flow of fluid in the core is affected by the capillary end effect, the relative permeability curve will change with the flow rate. Chen and Wood [18] confirmed the above viewpoint and pointed out that the relative permeability curve of mixed wet and water-wet samples has nothing to do with the flow rate. Later, Richardson [19] pointed out the capillary end effect will lead to the deviation of the relative permeability value and saturation value. The error of the saturation of the wetting phase is 15%. The error of relative permeability value of the wetting phase reaches 12%, and the error of relative permeability value of the non-wetting phase reaches 28%. Therefore, it is necessary to correct the capillary end effect.



**Figure 1.** Physical schematic figure of the capillary end effect. In order to achieve capillary balance, the wetting phase (blue) will gather at the outlet end. This phenomenon continues until the saturation of the wetting phase reaches the saturation when the capillary force is zero. However, the non-wetting phase (red) will not accumulate at the outlet end.

Many scholars have made some progress in correcting the capillary end effect problem. In 1957, Richardson [20] pointed out that increasing the length of the core sample or increasing the fluid flow rate can reduce the influence of the capillary end effect. Kyte and Rapoport [21] also found in 1958 that the influence of the capillary end effect will decrease with the increase of core length and fluid flow rate. Among them, the method of increasing the length of the core is not convenient for practical operation. The method of increasing the fluid flow rate is obviously not suitable for studying the characteristics of oil-water two-phase seepage under low-speed conditions. After theoretical research, Handley [22] introduced two dimensionless parameters to quantify the influence of the capillary end effect under steady-state conditions and obtained the core pressure profile representation equation and the non-wetting phase saturation profile representation equation. Huang and Honarpour [23] proposed a new method in 1998 to correct the capillary end effect using a capillary-saturation curve. This method only accurately corrects one point on the relative permeability curve. The other data depends on the empirical formula of relative permeability so that the error is large. Moreover, the calculation process of this method is relatively complicated. In 1988, Qadeer [24] established a mathematical model for estimating the relative permeability curve of oil and water in 1988 using an optimization algorithm. He provided a formula for correcting the capillary end effect. Lei [25] further improved this formula and corrected the endpoints of the relative permeability curve. This

correction formula is mainly for high permeability cores ( $k > 500$  mD) and is not applicable to low-permeability cores.

Romanenko et al. [26] used the nuclear magnetic resonance (NMR) method to quantitatively describe the capillary end effect in 2013. However the NMR measurement has certain errors, and this method is only suitable for high permeability rocks, not for strongly heterogeneous or fractured rocks. Su [27] pointed out in a 2018 invention patent that numerical simulation method can be used to eliminate the capillary end effect and make a corresponding correction chart [28]. This method is more dependent on the selection of the relative permeability formula. There are many types of relative permeability formulas. This makes the correction result inaccurate. Ashrafi and Helalizadeh [29] proposed a method to correct the capillary end effect of carbonate rock using a genetic algorithm in 2014. In this method, the selection of the empirical formulas for relative permeability and capillary may make the correction result not unique. Gupta and Maloney [30] proposed an intercept method to correct the capillary end effect by conducting steady-state experiments under different flow rates in 2016. However, this method assumes that the proportion of the length of the end effect is the same as the proportion of the pressure intercept, although it did not confirm it. Whether the hypothesis holds is open to question. Moghaddam [31] proposed that by conducting core relative permeability experiments at four different flow rates, the relative fluid permeability and fluid saturation can be obtained. This method requires four steady-state experiments to calculate the core length affected by the capillary end effect, relative fluid permeability, and fluid saturation. This method is more accurate than the previous method, but it requires more steady-state experiments, which is difficult to popularize on a large scale.

The existing methods for correcting the capillary end effect can be divided into two categories (Table 1). The first category is represented by the correction method proposed by Huang and Honarpour [23]. This method is based on the existing empirical formula of relative permeability to adjust the relative permeability curve. This type of correction method is more dependent on the selection of the empirical formula. The correction results of this type of method are diversified and accurate correction data cannot be obtained because the empirical formula of the correlation is more diversified. The second category is represented by the correction method proposed by Rasoul Nazari Moghaddam [31]. This method corrects the capillary end effect by constructing the pressure relationship between the region affected by the capillary end effect and the region not affected by the capillary end effect inside the core. Compared with the first type of correction method, this type of method does not rely on the selection of the relative permeability formula, so the correction result is more accurate. Moghaddam's method of measuring relative permeability experiments generally requires different proportions of injection at the same total flow rate. However, this method requires four experiments at each proportion of injection. As a result, this kind of method requires a large number of steady-state relative permeability experiments.

Based on previous work, this paper summarizes the law between the pressure drop and the length of the core affected by the capillary end effect. This paper introduces a stability factor to express the relationship between pressure drop and core length. In this paper, the relationship among core pressure drop, flow rate, and stability factor is derived. By this method, the relative permeability of the non-wetting phase that is not affected by the capillary end effect is obtained. This method simplifies the experimental process of correcting the end effect. It reduces the number of experiments without affecting the accuracy of the data. It provides a simple, effective, and feasible method for correcting the capillary end effect of the steady-state method for measuring relative permeability.

**Table 1.** Category of correction methods for capillary end effects.

Category	The First Category	The Second Category
Characteristic	This type of correction method is more dependent on the selection of the empirical formula.	This method corrects the capillary end effect by constructing the pressure relationship between the region affected by the capillary end effect and the region not affected by the capillary end effect inside the core.
Advantage	This kind of method requires once unsteady-state relative permeability experiments.	This type of method does not rely on the selection of the relative permeability formula, so the correction result is more accurate.
Disadvantage	The correction results of this type of method are diversified and accurate correction data cannot be obtained because the empirical formula of the correlation is more diversified.	This kind of method requires a large number of steady-state relative permeability experiments.
Reference number	[23–28]	[30,31]

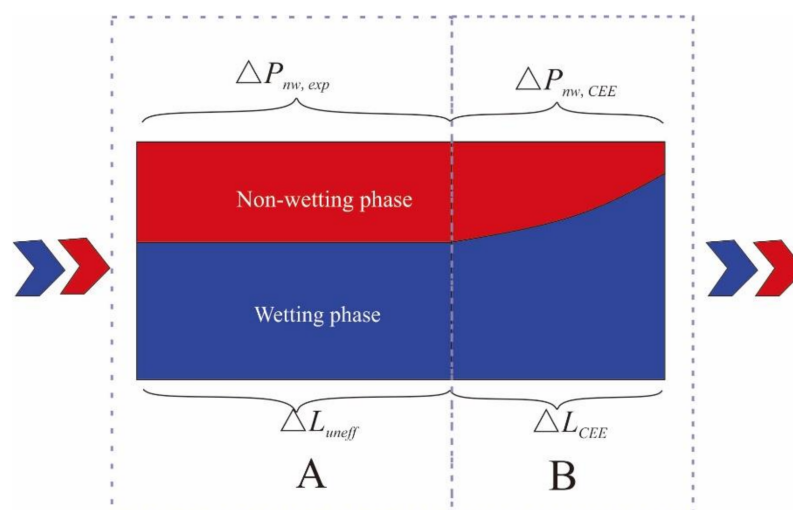
## 2. Materials and Methods

In the steady-state relative permeability measurement experiment, it is assumed that the two fluids are incompressible and immiscible. The following equation can be used to characterize the one-dimensional two-phase percolation law (taking the non-wetting phase as an example):

$$q_{nw} = \frac{Kk_{rnw}A}{\mu_{nw}} \frac{\Delta P_{nw}}{\Delta L} \quad (1)$$

As shown in Figure 2, the  $\Delta P_{nw,CEE}$  is the pressure drop caused by the capillary end effect. At this time, the measured pressure drop of the entire core is divided into the pressure drop not affected by the capillary end effect and the pressure drop affected by the capillary end effect:

$$\Delta P_{nw,exp} = \Delta P_{nw,uneff} + \Delta P_{nw,CEE} \quad (2)$$



**Figure 2.** Diagram of the internal conditions of the core (according to whether it is affected by the capillary end effect, the core is divided into two regions: A and B. The fluid in the core is divided into a wetting phase (blue) and a non-wetting phase (red)).



According to Darcy's law, we can get the relationship between the permeability and the flow rate in the region that is not affected by the capillary end effect.

$$q_{nw} = \frac{Kk_{rw,uneff}A}{\mu_{nw}} \frac{\Delta P_{nw,uneff}}{\Delta L_{uneff}} \quad (3)$$

Figure 2 shows the relationship between the length of each region in the core:

$$\Delta L_{uneff} = \Delta L - \Delta L_{CEE} \quad (4)$$

In Equation (4), the  $\Delta L_{CEE}$  is the length of the region affected by the capillary end effect. Substituting the  $\Delta P_{nw,CEE}$  in Equation (3) and the  $\Delta L_{uneff}$  in Equation (4) into Equation (2), the corresponding relationship between the measured pressure drop of the core and the relative permeability of the unaffected region can be obtained:

$$\Delta P_{nw,exp} = \frac{q_{nw}\mu_{nw}(\Delta L - \Delta L_{CEE})}{Kk_{rw,uneff}A} + \Delta P_{nw,CEE} \quad (5)$$

Since the relationship between  $\Delta P_{nw,CEE}$  and  $\Delta L_{CEE}$  in Equation (5) is not clear, we cannot solve  $k_{rw,uneff}$  directly. Experiments are now designed to study the relationship between the pressure drop caused by the capillary end effect and the length of the core region affected by the capillary end effect. In order to ensure the accuracy of the experimental results, the authors of this paper design three sets of steady-state experiments for measuring the oil-water relative permeability. The instrument used in the experiment is a new type of constant pressure and speed duplex pump manufactured by Jiangsu Shili Petroleum Scientific Research Instrument Co., Ltd. This instrument can inject two-phase fluid into the core at the same time, and record the inlet flow rate and pressure at any time. The oil used in this experiment is crude oil which viscosity is 20 cp at 20 °C. The water used in the experiment was pure water. The water viscosity is 1 cp at 20 °C. The core used in the experiment is the Changqing outcrop core. The core is mainly fine sand with a small amount of medium sand. As for Tables 2 and 3 and Figure 3, the composition of the core is mainly composed of quartz and calcite. Since the content of clay minerals in the core is small, the swelling effect of clay minerals has little influence on the experimental results. Figure 4 is the experimental flowchart.

**Table 2.** Basic data of the core.

Core Number	Length/cm	Diameter/cm	Area/cm <sup>2</sup>
60-1	7.990	2.540	1.613
Porosity/%	Absolute permeability/D	Dry weight/g	Wet weight/g
19.778	0.0631	84.739	93.027

**Table 3.** X-ray diffraction test results table.

Core Number	Component Content (%)				
	Quartz	Potash Feldspar	Plagioclase	Calcite	Dolomite
60-1	68	1	5	25	1
	Pyrite	Barite	Anhydrite	Analcite	Hematite
	0	0	0	0	0

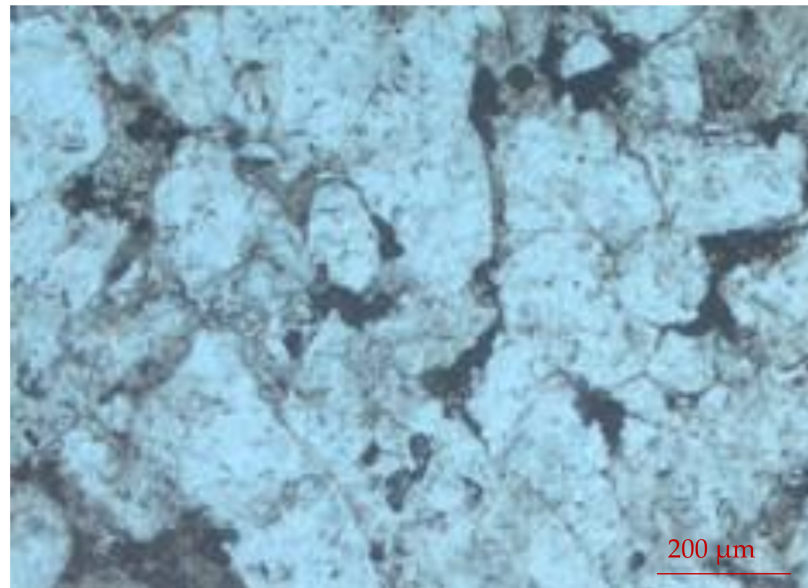


Figure 3. Diagram of the internal conditions of the core.

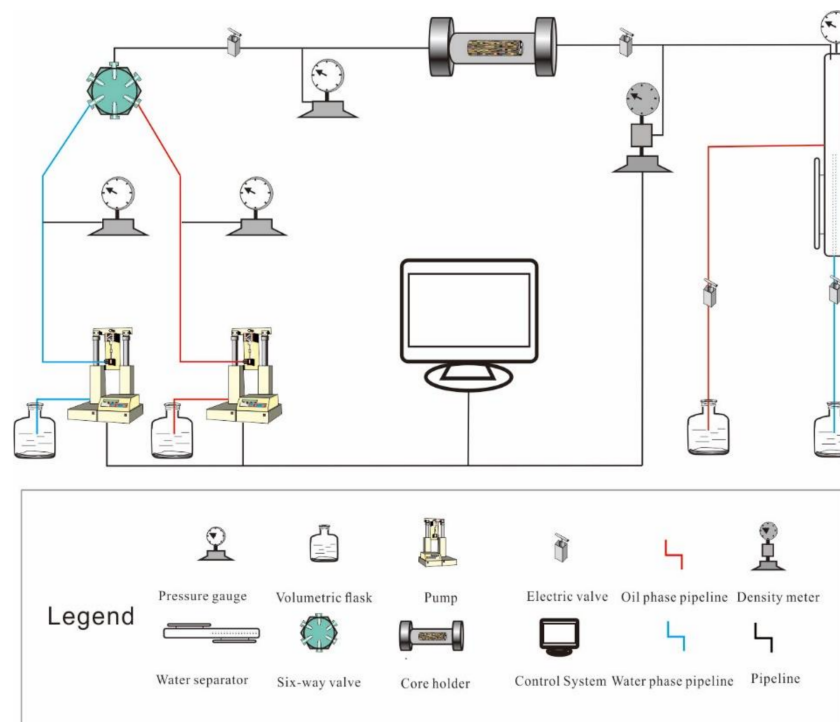


Figure 4. Experimental flowchart (the wetting phase and the non-wetting phase are injected into the core through a pump. The flow rates at the inlet and outlet ends of the core are measured and transmit the measurement data to the control system).

The experimental steps are as follows:

1. First, the rock sample is cleaned. The original wettability of the reservoir is water wet. In the experiment, benzene and alcohol were used to clean the rock sample;
2. Then the core is evacuated and dried. Weigh the dry core and record the dry weight. Then the core is saturated with water, and the water-saturated rock sample is weighed. The wet weight of the core can be obtained. The effective pore volume and porosity are obtained by using the dry weight and wet weight of the core;

3. The oil is injected into the core which is saturated with water. Then carry out the core displacement experiment and make the core reach the state of irreducible water;
4. Record the amount of water and oil at the outlet; it prepares for calculating the relative permeability of oil and water under a certain oil-water ratio and different total flow rates. According to Table 4, oil and water are injected into the rock sample at a specific ratio. When the flow is stable (the pressure difference between the two ends of the rock sample is stable), we record the inlet and outlet pressures. Then use a density meter to get the water cut of the liquid at the outlet. The water saturation of the core is obtained according to the principle of material balance;
5. Under the condition of the same proportion of injected liquid (wetting phase and non-wetting phase), change the total flow rate. Systematically varying the flow rate, repeat the previous step until the end of the experimental run with that imposed ratio between phases.

**Table 4.** Experimental design table.

Experiment Number	Proportion of Injected Liquid	Total Flow Rates/(mL/min)	$q_{nw}/(\text{mL}/\text{min})$	$q_w/(\text{mL}/\text{min})$
1	1:10	0.3	0.027	0.273
2	1:10	0.6	0.055	0.545
3	1:10	1.1	0.100	1.000
4	1:10	2.2	0.200	2.000
5	1:10	1.1	0.100	1.000
6	5:01	0.3	0.250	0.050
7	5:01	0.6	0.500	0.100
8	5:01	1.1	0.917	0.183
9	5:01	2.2	1.833	0.367
10	1:10	1.1	0.100	1.000
11	1:05	0.3	0.050	0.250
12	1:05	0.6	0.100	0.500
13	1:05	1.1	0.183	0.917
14	1:05	2.2	0.367	1.833
15	1:10	1.1	0.100	1.000

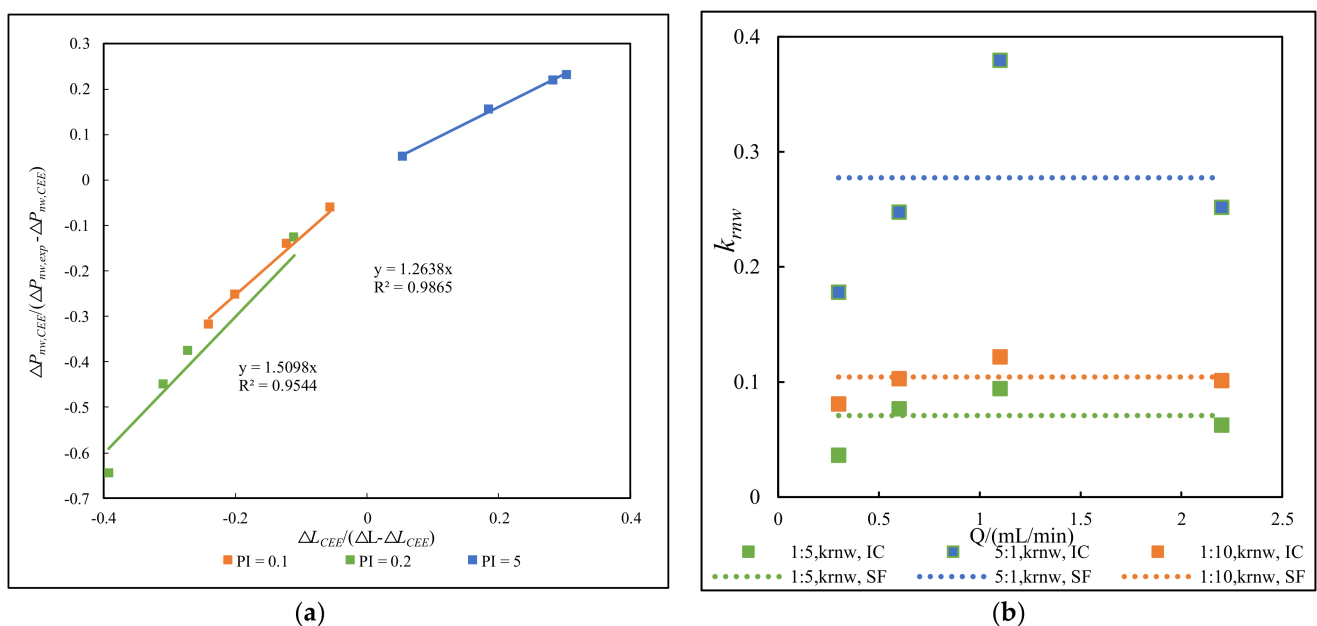
Table 4 is a summary table of flow rates under three different injections rates. A total of 12 displacement experiments were carried out, for four total flow rates, 0.3, 0.6, 1.1, and 2.2 mL/min, and each of them for three oil-water ratios, 5:1, 1:5, and 1:10. After each displacement run with fixed phase ratios, experiment 3 is repeated in order to ensure the accuracy of the procedure; corresponding tests are labeled 5, 10, and 15 in Table 5. It is observed that each time the results do not have significant change and the experiments are reproducible. This can lead to two conclusions. First, the core pore structure has not changed; second, the experimental data is accurate. We make sure that the internal structure of the core has not changed by comparing the changes in flow rate, pressure difference, and water saturation. This method can ensure the accuracy of subsequent experimental results. In this paper, 12 displacement experiments and 3 repeated experiments were carried out.

**Table 5.** Data from repeated experiments.

Experiment Number	Proportion of Injected Liquid	Pressure Drop/MPa	Water Saturation
3	1:10	7.420	0.420
5	1:10	7.924	0.412
10	1:10	7.991	0.437
15	1:10	7.210	0.457

### 3. Results

In the experiment, the pressure and total flow rate are recorded; then by using the intercept method [30],  $\Delta P_{nw,CEE}$  and  $\Delta L_{nw,CEE}$  are evaluated, in order to explore the correlation between them. Draw the relationship between  $\frac{\Delta P_{nw,CEE}}{\Delta P_{nw,exp} - \Delta P_{nw,CEE}}$  and  $\frac{\Delta L_{CEE}}{\Delta L - \Delta L_{CEE}}$  according to the corrected result. The intercept method is shown in Appendix A. It can be found from Figure 5a that under the PI (the same proportion of injected liquid (the wetting phase and the non-wetting phase)), the same ratio between  $\frac{\Delta P_{nw,CEE}}{\Delta P_{nw,exp} - \Delta P_{nw,CEE}}$  and  $\frac{\Delta L_{CEE}}{\Delta L - \Delta L_{CEE}}$  can be obtained. There is a stable proportional relationship between  $\frac{\Delta P_{nw,CEE}}{\Delta P_{nw,exp} - \Delta P_{nw,CEE}}$  and  $\frac{\Delta L_{CEE}}{\Delta L - \Delta L_{CEE}}$ . We have made a linear fit between  $\frac{\Delta P_{nw,CEE}}{\Delta P_{nw,exp} - \Delta P_{nw,CEE}}$  and  $\frac{\Delta L_{CEE}}{\Delta L - \Delta L_{CEE}}$ . The fitting coefficients are all greater than 0.95, and the fitting effect is very satisfactory. Now the ratio of  $\frac{\Delta P_{nw,CEE}}{\Delta P_{nw,exp} - \Delta P_{nw,CEE}}$  to  $\frac{\Delta L_{CEE}}{\Delta L - \Delta L_{CEE}}$  is defined as the stability factor, as shown in Equation (6).



**Figure 5.** PI = 0.1 (orange); PI = 0.2 (green); PI = 5 (blue). The calculation and application of the stability factor: (a) Calculation of stability factor; (b) comparison of wetting phase correction results between the stability factor method (SF) and the intercept method (IC).

$$\frac{\Delta P_{nw,CEE}}{\Delta P_{nw,exp} - \Delta P_{nw,CEE}} \div \frac{\Delta L_{CEE}}{\Delta L - \Delta L_{CEE}} = \beta \tag{6}$$

The capillary end effect factor is now defined to represent the ratio of the length affected by the capillary end effect to the total length of the core, as like  $\alpha = \Delta L_{CEE} / \Delta L$ . The introduction of the concept of stability factor ( $\beta$ ) in this paper can reduce the number of experiments for the subsequent correction of capillary end effects. We can obtain the relationship between the capillary end effects factor and the stability factor:

$$\alpha = \frac{\Delta P_{nw,CEE}}{(\Delta P_{nw,CEE} - \Delta P_{nw,CEE})\beta + \Delta P_{nw,CEE}} \tag{7}$$

Then Equation (7) is incorporated into Equation (5) to obtain the corresponding relationship between the measured pressure drop of the core and the stability factor:

$$\Delta P_{nw,exp} = \Delta P_{nw,CEE} + \frac{q_{nw}\mu_{nw}\Delta L}{KA} \times \frac{(\Delta P_{nw,exp} - \Delta P_{nw,CEE})\beta}{[(\Delta P_{nw,exp} - \Delta P_{nw,CEE})\beta + \Delta P_{nw,CEE}]k_{r,w,uneff}} \tag{8}$$

After finishing Equation (8), we can get:

$$\Delta P_{nw,exp} = \frac{q_{nw}\mu_{nw}\Delta L}{KA} \frac{1}{k_{rnw,uneff}} + \Delta P_{nw,CEE} - \frac{\Delta P_{nw,CEE}}{\beta} \quad (9)$$

Moghaddam [31] pointed out that the value of relative permeability is related to the proportion of injected liquid and does not depend on the flow rate. According to Equation (9) and two steady-state displacement experiments of oil and water, the values of  $k_{rnw,uneff}$  and  $\Delta P_{nw,CEE} - \frac{\Delta P_{nw,CEE}}{\beta}$  can be obtained.

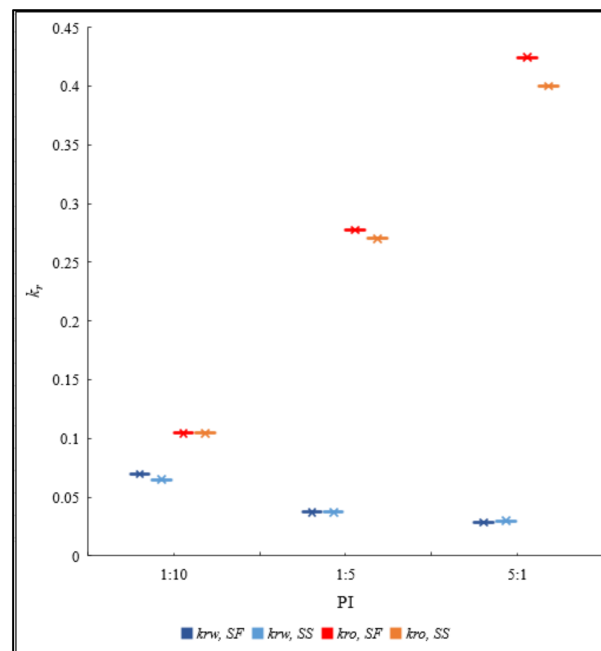
$$\begin{cases} \Delta P_{nw,exp}^1 = \frac{q_{nw}^1\mu_{nw}\Delta L}{KA} \times \frac{1}{k_{rnw,uneff}} + \Delta P_{nw,CEE} - \frac{\Delta P_{nw,CEE}}{\beta} \\ \Delta P_{nw,exp}^2 = \frac{q_{nw}^2\mu_{nw}\Delta L}{KA} \times \frac{1}{k_{rnw,uneff}} + \Delta P_{nw,CEE} - \frac{\Delta P_{nw,CEE}}{\beta} \end{cases} \quad (10)$$

According to Equation (10), take  $\frac{q_{nw}^i\mu_{nw}\Delta L}{KA}$  as the abscissa and  $\Delta P_{nw,exp}^i$  as the ordinate to establish a rectangular coordinate system. The reciprocal of the slope is  $k_{rnw,uneff}$ , and the intercept is  $\Delta P_{nw,CEE} - \frac{\Delta P_{nw,CEE}}{\beta}$ . Therefore, the relative permeability of the water phase that is not affected by the capillary end effect can be obtained by two steady-state experiments. This method reduces the workload by half compared with the previous experimental design [31].

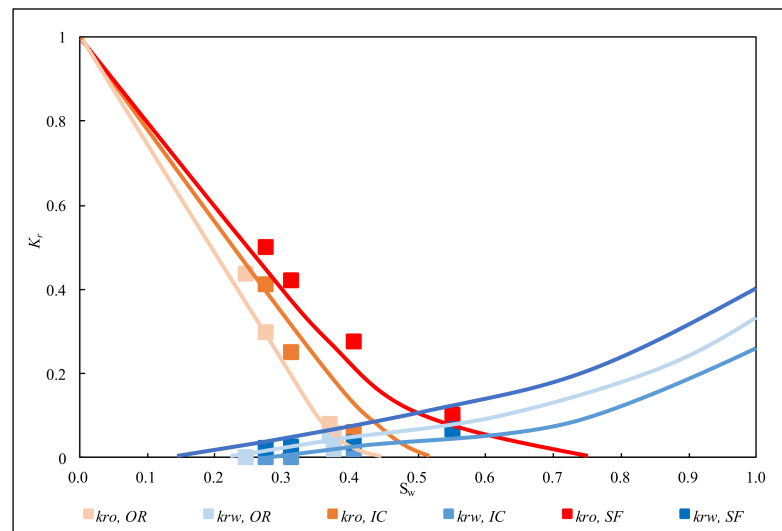
The stability factor is used to calculate the relative permeability of the wetting phase and the non-wetting phase in this paper. The repeated process is as follows. First of all, we need to test the relative permeability of oil and water with two steady-state experiments of the core. It should be noted that the two experiments need to be carried out at the same oil-water proportion. After the experiment, we can get  $\Delta P_{nw,exp}^1$ ,  $\Delta P_{nw,exp}^2$ ,  $q_{nw}^1$  and  $q_{nw}^2$ . Second, we can get  $k_{rnw,uneff}$  and  $\Delta P_{nw,CEE} - \frac{\Delta P_{nw,CEE}}{\beta}$ . Since this method is calculated based on the stability factor, this method is named the stability factor method. And the correction results are compared with the intercept method proposed by Gupta and Maloney [30], as shown in Figure 5b. Figure 5b shows the comparison of the relative permeability of the wetting phase between the stability factor method and the intercept method under different total flow rates. Under the same oil-water ratio, the relative permeability should not change with the total flow rate. The intercept method obviously does not conform to this law. This method believes that the seepage capacity of the A and B (Figure 2) is the same. This view is obviously wrong. It can be found from Figure 5b that whether it is for the wetting phase or the non-wetting phase, the stability factor method is free from these drawbacks and can reasonably be considered as a more accurate one. In order to ensure the accuracy of the experimental results, this paper uses the correction results of Moghaddam [31] to compare the results of the method in this paper, as shown in Figure 6. As mentioned earlier, the correction result of Moghaddam [31] is accurate, but the number of experiments is more than other methods. This paper will use this method as a standard to measure the accuracy of the correction result of the method in this paper. It can be seen from Figure 6 that the correction result error between the stability factor method and the standard method is small, which further demonstrates the accuracy of the stability factor method.

Figure 7 shows the comparison among the original relative permeability curve, the relative permeability curve corrected by the intercept method, and the stability factor method. The OR/IC/SF in Figure 7 are the original experimental data, the repeated result of the intercept method, and the repeated result of the stability factor method. It is observed that the relative permeability value of the corrected wetting phase and non-wetting phase is significantly enhanced. The end effect hinders the flow of the non-wetting phase. Affected by the capillary end effect, the residual oil saturation of the non-wetting phase increased by 30%. If the error of capillary end effect is not corrected, accurate relative permeability data cannot be provided for reservoir production.





**Figure 6.** Comparison of the correction results of the wetting phase and the non-wetting phase of the stability factor method (SF) and the method proposed by Moghaddam (SS) when the PI = 0.1, PI = 0.2, and PI = 5.



**Figure 7.** Comparison among the original relative permeability curve (OR), the relative permeability curve corrected by the intercept method (IC), and the stability factor method (SF).

#### 4. Discussion

To ensure the accuracy of the conclusions obtained, we use the experimental data of Moghaddam [31] to verify the feasibility of the stability factor method. The experimental data of Moghaddam [31] is now used to study the relationship between the pressure drop caused by the capillary end effect and the length of the core region affected by the capillary end effect.

The basic data of the core is shown in Table 6.

**Table 6.** Basic core data [31].

Core Number	$\Delta L/\text{cm}$	$D/\text{cm}$	$A/\text{cm}^2$	$\Phi/\%$	$K/\mu D$
-	4.61	3.77	11.16	13.5	9.9

The pressure drop and flow data at both ends of the core measured in the experiment are shown in Table 7.

**Table 7.** Experimental data of core affected by capillary end effect under different flow rates.

Experiment Number	$q_w/q_{nw}$	$q_{nw}/(\text{mL}\cdot\text{min}^{-1})$	$\Delta P_{nw,exp}/\text{atm}$
1		0.07	3.95
2	0.08	0.08	4.82
3		0.25	13.51
4		0.50	26.55
5		0.18	6.46
6	0.02	0.25	8.42
7		0.42	13.31
8		0.83	25.53

Table 7 is a summary table of pressure and flow rate under two different injection ratios of wetting phase and non-wetting phase. In each injection ratio, steady-state methods to measure the relative permeability of oil and water experiments were carried out at four different flow rates. The flow rate and pressure drop of each experiment were recorded separately. Table 8 shows the corrected pressure drop and core length in the region where the capillary end effect occurs in the experimental data of Moghaddam [31]. Each of the same proportion of injected liquid of wetting phase and non-wetting phase conditions has the same value of  $\Delta P_{nw,CEE}$ . According to the corrected results, the relationship between  $\frac{\Delta P_{nw,CEE}}{\Delta P_{nw,exp} - \Delta P_{nw,CEE}}$  and  $\frac{\Delta L_{CEE}}{\Delta L - \Delta L_{CEE}}$  is shown in Figure 8a.

**Table 8.** Stability factor calculation table.

Number	$\Delta P_{nw,CEE}/\text{atm}$	$\Delta L_{CEE}/\text{cm}$	$\beta$
1	2.87	3.18	1.20
2	2.87	2.54	1.20
3	2.87	0.85	1.20
4	2.87	0.42	1.20
5	6.04	4.25	1.22
6	6.04	3.11	1.22
7	6.04	1.87	1.22
8	6.04	0.93	1.22

It can be found from Table 8 that under the same injection ratio, there is a certain proportional relationship between  $\Delta P_{nw,CEE}$  and  $\Delta L_{CEE}$ . With the difference in the total flow rate, the stability factor is constant. It is only related to the proportion of injected liquid of the wetting phase to the non-wetting phase in the steady-state method of measuring the relative permeability of oil and water and has nothing to do with the total flow rate.

It is necessary to verify whether the reduction of the number of experiments has an impact on the accuracy of the experimental results. In this paper, the corrected result calculated by the stability factor is compared with the original result. Table 9 shows the specific numerical values of  $x_i$ ,  $y_i$ ,  $k_{rnw,eff}$  and  $\Delta P_{nw,CEE} - \frac{\Delta P_{nw,CEE}}{\beta}$ . In the table, the unit of  $x_i$  and  $y_i$  is atm.

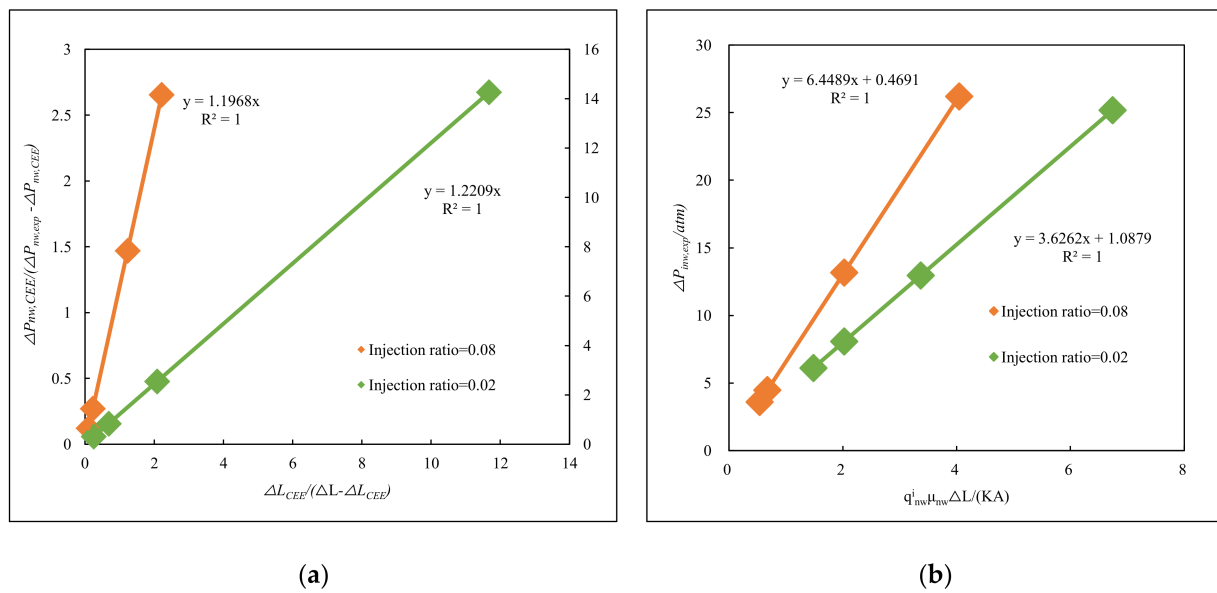


Figure 8. Application examples of stability factor: (a) Calculation of stability factor; (b) application of stability factor.

Table 9. Calculation results of relative permeability.

Number	$y_i$	$x_i$	$k_{nw,uneff}$	$\Delta P_{nw,CEE} - \frac{\Delta P_{nw,CEE}}{\beta}$
1	3.95	0.0054	0.1510	0.048
2	4.82	0.0067		
3	13.51	0.0202	0.1510	0.048
4	26.55	0.0404		
5	6.46	0.0148	0.2685	0.110
6	8.42	0.0202		
7	13.31	0.0337	0.2685	0.110
8	25.53	0.0674		

In Figure 8b,  $\frac{q_{nw}^i \mu_{nw} \Delta L}{KA}$  is the abscissa and  $\Delta P_{nw,exp}^i$  is the ordinate. According to the stability factor, it can be found that  $\frac{q_{nw}^i \mu_{nw} \Delta L}{KA}$  and  $\Delta P_{nw,exp}^i$  have an obvious linear relationship. The reciprocal of the slope in the figure is the relative permeability of the non-wetting phase. The intercept is the result of the interaction of  $\Delta P_{nw,exp}^i$  and  $\frac{q_{nw}^i \mu_{nw} \Delta L}{KA}$ . Under the same proportion of injected liquid of wetting and non-wetting phases, they have the same slope and intercept. That is to say, there is no need for the four-time steady-state method to measure relative permeability experimental data. Only two sets of experiments are needed to obtain the relative permeability of the non-wetting phase that is not affected by the capillary end effect. The linear relationship between  $\Delta P_{nw,exp}^i$  and  $\frac{q_{nw}^i \mu_{nw} \Delta L}{KA}$  under the four flow rates can be found to be consistent with the two groups when calculated separately. These four points are exactly on the same straight line. The  $R^2$  of each fitted straight line is above 1. It shows that the change of the proportion of injected liquid of the wetting phase and the non-wetting phase does not affect the linear law.

From Figure 8b, it can be concluded that how to change the proportion of injected liquid of the wetting phase and the non-wetting phase. As long as the proportion of injected liquid is the same, there is no need for the previous four steady-state experiments to measure relative permeability. In the method shown in this paper, only two sets of experimental data are needed to obtain the relative permeability of the non-wetting phase that is not affected by the capillary end effect. This method reduces the number of experiments and greatly saves time and cost.

As shown in Table 10,  $k_{rnw}$  is the relative permeability value of the non-wetting phase obtained by the stability factor method. The  $k_{rnw}^*$  is the relative permeability value obtained by Moghaddam's method. The  $|k_{rnw}^*|$  is the absolute value between the two errors. The magnitude of  $|k_{rnw}^* - k_{rnw}|$  is much smaller than  $k_{rnw}$  and  $k_{rnw}^*$ . Therefore, the error caused by the stability factor method is within the allowable range of error. It is proved that this method not only reduces the number of experiments but also calculates the relative permeability of the non-wetting phase very accurately. The problem of correcting the capillary end effect of relative permeability under low-velocity seepage conditions can be dealt with more efficiently.

**Table 10.** The experimental data of Moghaddam is corrected for the end effect. Comparison of Moghaddam's method and the relative permeability correction result of the stability factor method.

Number	$k_{rnw}$	$k_{rnw}^*$	$ k_{rnw}^* - k_{rnw} $
1	0.155	0.155	$3.53 \times 10^{-6}$
2			
3			
4			
5	0.276	0.155	$9.4 \times 10^{-5}$
6			
7			
8			

## 5. Conclusions

The stability factor method summarizes the law between the pressure drop caused by the end effect and the core region. It can reduce the number of correction experiments by half, thereby reducing the manpower, material resources, and time required. Research shows that under the same injection ratio, the core has the same stability factor in the experiment of measuring the relative permeability of oil and water by the steady-state method. The stability factor does not change with the total flow rate. In addition, under the same injection ratio, the stability factor method only requires two steady-state methods to measure the relative permeability experiment to obtain the corrected relative permeability value of the non-wetting phase. It not only guarantees the accuracy of the results (the error is less than 0.01) but also simplifies the experimental process.

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## List of Symbols

$q_{nw}$	Non-wetting phase flow rates, mL/min
$\Delta L$	The length of the core, cm
$K$	Absolute permeability, $\mu\text{m}^2$
$A$	Area, $\text{cm}^2$
$\beta$	Stability factor

$i$	Number of experiments
$\Delta L_{CEE}$	Core length affected by capillary end effect, cm
$\Delta P_{nw,exp}$	Pressure drop of the non-wetting phase measured in the experiment, atm
$\Delta P_{nw,uneff}$	Pressure drop unaffected by the capillary end effect, atm
$\Delta P_{nw,CEE}$	The pressure drop affected by the capillary end effect, atm
$k_{rnw,uneff}$	Relative permeability of non-wetting phase unaffected by capillary end effect
$k_{rnw}$	Relative permeability of non-wetting phase calculated by the stability factor method
$k_{rnw}^*$	The relative permeability of the non-wetting phase calculated by Moghaddam's method

## Appendix A

Gupta and Maloney [30] proposed an intercept method to correct the capillary end effect by conducting steady-state experiments under different flow rates in 2016. This method requires running a steady-state relative permeability test with several different flow rates for each fractional flow. First, take the non-wetting phase as an example to establish Darcy's formula as follows:

$$q_t(1 - F_w) = \frac{Kk_{rnw,uneff}A}{\mu_{nw}\Delta L} (\Delta P_{nw,exp} - \Delta P_{nw,CEE}) \quad (A1)$$

Rearranging Equation (A1) gives:

$$\Delta P_{nw,exp} = \frac{q_t\mu_{nw}\Delta L}{Kk_{rnw,uneff}A} (1 - F_w) + \Delta P_{nw,CEE} \quad (A2)$$

The  $\Delta P_{nw,exp}$  can be expressed as the pressure drop of the non-wetting phase measured in the experiment. The  $\Delta P_{nw,CEE}$  can be expressed as the pressure drop affected by the capillary end effect. The  $\Delta P_{nw,uneff}$  is the pressure drop unaffected by the capillary end effect. The  $q_t$  is the total flow rate and the  $F_w$  is the wetting phase fractional flow. Using the above concept, Gupta and Maloney proposed to obtain  $\Delta P_{nw,CEE}$  from the intercept of the plot of  $\Delta P_{nw,exp}$  and the injected total flow rate ( $q_t$ ).

To correct the saturation data, they used the following overall saturation balance equation for a given fractional flow condition:

$$\Delta L S_{nw,exp} = (\Delta L - \Delta L_{CEE}) S_{nw,uneff} + S_{nw,CEE} \Delta L_{CEE} \quad (A3)$$

The  $S_{nw,exp}$  can be expressed as the saturation of the non-wetting phase measured in the experiment. The  $S_{nw,CEE}$  can be expressed as the saturation affected by the capillary end effect. The  $S_{nw,uneff}$  is the saturation unaffected by the capillary end effect.

And they proposed a capillary end effect length factor  $\beta$ , and hypothesized:

$$\beta = \frac{\Delta L_{CEE}}{\Delta L} = \frac{\Delta P_{nw,CEE}}{\Delta P_{nw,exp} - \Delta P_{nw,CEE}} \quad (A4)$$

Rearranging Equation (A3) and using Equation (A4) gives the expression:

$$\frac{1}{1 - \beta} S_{nw,exp} = S_{nw,CEE} \frac{\beta}{1 - \beta} + S_{nw,uneff} \quad (A5)$$

Based on Equation (A5),  $S_{nw,uneff}$  is the intercept of the plot of  $\frac{1}{1 - \beta} S_{nw,exp}$  and  $\frac{\beta}{1 - \beta}$ .

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