[EA]Movable Fluid Distribution and the Permeability Estimation in Tight Sandstones Using NMR*

Chaohui Lyu[1,2], Zhengfu Ning[1,2], Qing Wang[1,2], and Mingqiang Chen[1,2]

Search and Discovery Article #42544 (2020)**
Posted June 29, 2020

*Adapted from extended abstract based on oral presentation given at 2018 AAPG Annual Convention & Exhibition, Salt Lake City, Utah, May 20-23, 2018

[1]State Key Laboratory of Petroleum Resources and Prospecting, China University of Petroleum (Beijing), Beijing 102249, China (lvchaohui521@163.com)
[2]Department of Petroleum Engineering, China University of Petroleum (Beijing), Beijing 102249, China

Abstract

An accurate understanding of movable fluid distribution and permeability are crucial for the successful exploitation of tight oil reservoirs. However, tight oil reservoirs typically show a wide pore size distribution with pore sizes ranging from several nanometers to several hundred microns. Now existing permeability estimation parameters are no longer suitable for tight sandstones. Therefore, this article explores the applicability of nuclear magnetic resonance (NMR) on movable fluid distribution and the permeability estimation in tight sandstones. Six sets of NMR experiments are carried out on samples from the Chang 6 Formation in Ordos Basin. The first one is performed on fully water saturated plugs to obtain the fluid distribution. The remaining five are conducted on the same plugs after centrifuged at different centrifugal force to determine movable fluid distribution. In order to further confirm the pore-throat morphology occupied by movable fluid, we carry out scanning electron microscopy on core slices. Based on the statistics of movable fluid distribution, a modified Coates model is developed for permeability prediction in tight sandstones. In terms of the study, the following conclusions are arrived at. The optimum centrifugal pressure for the Chang 6 Formation is 208 psi and pores with radii less than 0.1 μm show no obvious difference with throats. Movable fluid is mostly controlled by throats with radii less than 1 μm, especially throats radii ranging from 0.3 μm to 1 μm. Movable fluid is stored in pores distributed around the right peak of the bimodal distribution with radii ranging from 10 μm to 100 μm. These pores are residual interparticle pores and dissolution pores. Four types of pore throat combination are identified using scanning electron microscopy, among which shrinking throats and flaky throats are common. A formula describing permeability based on the Coates model for a tight sandstone oil reservoir derived from the results matches the Formation's permeability with an excellent correlation factor of 0.90 when the value in the Coates model equals 19. Petrophysical characterization by NMR technique provides an effective approach to better understand pore throat structures and storage capacity of tight oil reservoirs.

Introduction

With the depletion of conventional oil reservoirs and advances in hydraulic fracturing techniques, tight oil reservoirs are now considered an important alternative resource (EIA, 2013). An understanding of flowability of tight oil reservoirs is essential for successful exploitation. 100 psi is often chosen as the optimum centrifugal force for conventional sandstones to determine the movable fluid and the bound fluid (Zhou et al., 2011; Ohen et al., 1996). However, the applicability of 100 psi for tight sandstones is still an open question; at the same time the applicability of the permeability estimation based on NMR need to be researched (Coates, 1999).

Experimental

Properties of six subsurface samples can be seen in Table 1. A PANalytical diffractometer was used to acquire the relative mineral percentages, estimated by a semi-quantitative method. It was performed on powdered tight sandstone at room temperature (293.15 K) under a relative humidity of 66%. Fresh sections and polished samples were coated with gold and then observed by a FEI™ Quanta™ 200F SEM (20 KV, High vacuum mode). The SEM used in this study provides a resolution of 1.2 nm and a magnification of × 25 k – 200 k. NMR measurements are here briefly described (Figure 1). First, six core samples for NMR measurements are dried at 378.15 k for 24 hours. Then the core samples were weighed and measured (length and diameter). Second, samples are evacuated for 2 hours and then saturated with distilled water under 25 MPa for 48 hours. The saturated weight is recorded. The water porosity of each core is calculated using the dry weight, the wet weight, and the volume of the sample. Third, raw NMR data of water-saturated cores are performed. Fourth, five sets of NMR experiments are conducted after each centrifugation. The weight of each core sample is measured after each centrifugation. Fluid balance in each sample was obtained by keeping the core samples still for ten minutes before each NMR measurement. Five centrifugal pressures were used: 21 psi, 84 psi, 208 psi, 418 psi, 696 psi.

Methodology

The centrifugal pressure under different speed of revolution can be expressed as:

$$P_{\text{centri}} = 1.097 \times 10^{-9} \Delta\rho n^2 L(R - \frac{L}{2}) \qquad (1)$$

where P_{centri} is the centrifugal pressure, MPa; $\Delta\rho$ is the density difference of air and water, g/cm^3, n is the speed of revolution, r/min; R is the radius of sample, cm; L is the length of sample, cm. The capillary is expressed as:

$$p_c = \frac{2\sigma \cos\theta}{r} \qquad (2)$$

where P_c is the capillary pressure, MPa; σ is the interfacial tension, mN/m; θ is the contact angle, °; r is the pore radius, cm. Therefore, centrifugal radius under different speed of revolution can be calculated based on Equation (1) and Equation (2), namely 1 μm, 0.3 μm, 0.1 μm, 0.05 μm, 0.03 μm.

The movable fluid after each centrifugation can be considered as movable fluid controlled by two corresponding centrifugal pressures. The optimum centrifugal force suitable for tight sandstone reservoirs can be determined by using the linear regressions of (a) the curve showing the cumulative percentage of movable fluid vs. gas permeability, and (b) the curve showing gas permeability vs. the percentage of movable fluid at each centrifugal stage (Table 2).

Based on the Timur equation, Coates conducted a large number of experiments and developed a model, called the Coates model, to predict permeability using NMR porosity and the percentage of movable fluid. Coates model can be described by the following equation:

$$K_c = \left(\frac{\phi}{C_c}\right)^4 \left(\frac{FFI}{BVI}\right)^2 \tag{3}$$

Where K_C is the permeability (10^{-3} μm^2) predicted by Equation (3), ϕ is the NMR porosity (%), FFI is the movable fluid percentage and BVI is the bound fluid percentage, which can be determined based on the optimum centrifugal force, C_C, which is a constant related to the reservoir formation. Therefore, C_C is the only variable that should be determined to quantify this equation for the Chang 6 Formation.

Previous study demonstrates that SDR always overestimates the permeability and is suitable for sandstone with good sorting and high permeability. The SDR (Schlumberger Doll Research) model can be expressed as follows:

$$K_S = C_S \phi^4 {T_{2gm}}^2 \tag{4}$$

Where K_S is the permeability (10^{-3} μm^2) predicted by Equation (4), ϕ is NMR porosity (%), T_{2gm} is the geometric mean of NMR transversal relaxation time, C_S is a constant related to formation. The linear regressions between K_a and $\phi^4 {T_{2gm}}^2$ were used to validate the SDR model for the Chang 6 tight oil reservoirs.

Conclusions

(1) Four throat types were observed (Figure 1), which are necking throats, shrinking throats, flakey throats, and tubal throats. The radii of the four throat types are mainly ranging in nanoscale, resulting in the creation of a large amount of pores with a large pore throat ratio being present in the tight sandstone reservoir.

(2) The optimum centrifugal force for the Chang 6 Formation is 208 psi (Figure 2). More than 70% of movable fluid is controlled by throats which have a radius lower than 1 μm. Throats with radii between 0.3 μm and 1 μm are the most common ones. The threshold radius through which movable fluid would flow is 0.1 μm. Pores and throats show no movement of fluid when pore radius is less than 0.1 μm. Based on the movable fluid distribution (Figure 3), the peak is around dozens of microns which indicates that movable water is mainly stored in residual interparticle pores and the dissolution pores.

(3) The applicability of the Coates model and the SDR model on tight oil reservoirs are discussed based on a study of core samples from the Chang 6 Formation. An accurate estimation of the permeability for the Chang 6 Formation is presented based on the Coates model (Figure 4). C_C is much larger in tight sandstones. The SDR model (Figure 5) is not suitable for the estimation of permeability in tight oil reservoirs.

References Cited

Coates, G.R., L.Z. Xiao, and M.G. Prammer, 1999, NMR Logging Principles & Application: Halliburton Energy Services Publication H02308.

EIA, USA, 2013, Technically recoverable shale oil and shale gas resources: An assessment of 137 shale formations in 41 countries outside the United States: US Department of Energy/EIA, Washington, DC.

Ohen, H., A. Ajufo, and P. Enwere, 1966, Laboratory NMR relaxation measurements for the acquisition of calibration data for NMR logging tools: Oil Well, p. 329-342.

Zhou, Y., G. Wei, and H. Guo, 2011, Impact factors analysis and decision tree correction of NMR porosity measurements: Well Logging Technology, v. 35/3, p. 210-214.

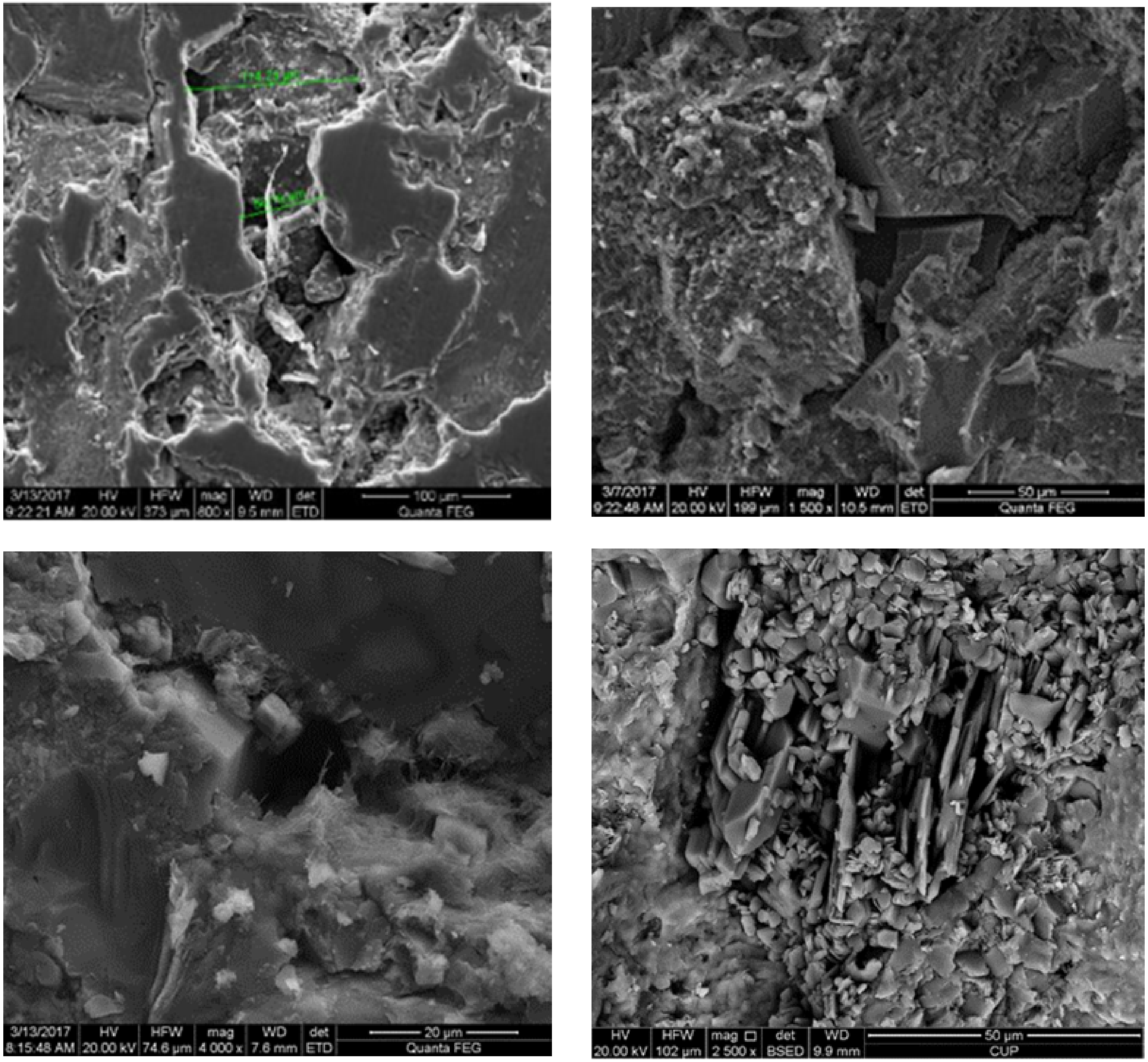

Figure 1. SEM results, showing the four types of pore throats.

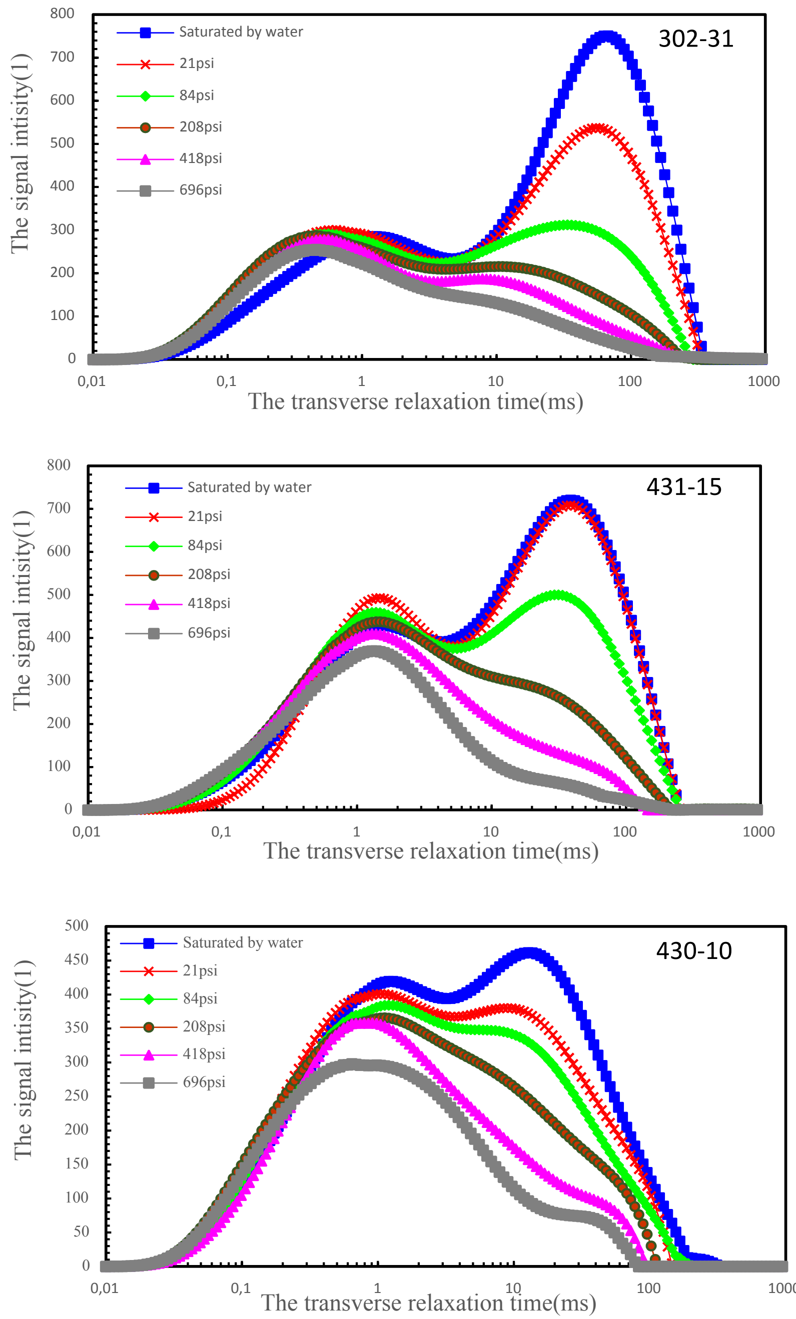

Figure 2. Centrifugation results.

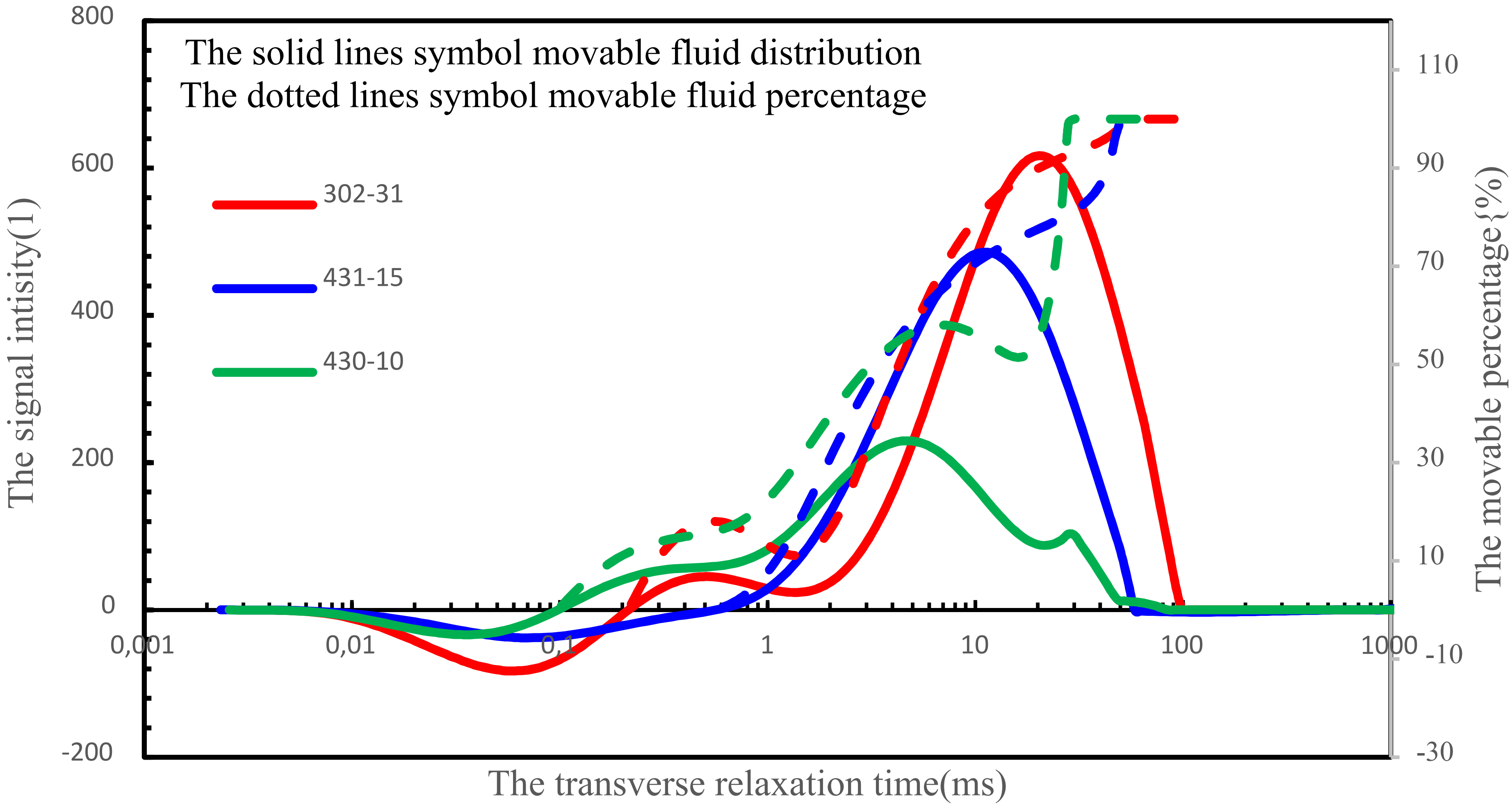

Figure 3. Movable fluid distributions and movable fluid percentage distributions for samples.

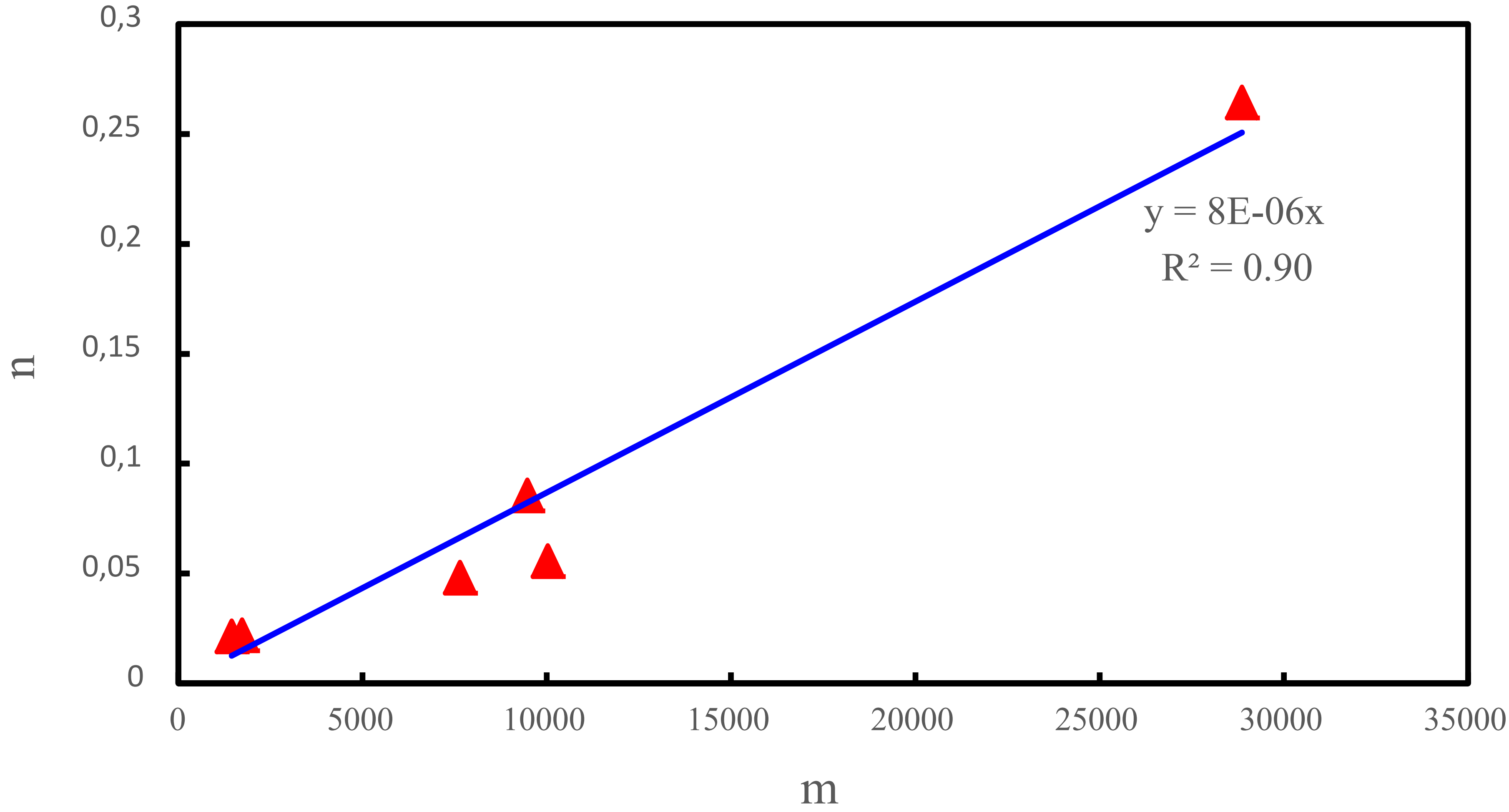

Figure 4. The regression analysis between $(\phi)^4(\frac{FFI}{BVI})^2$ and K_a. (m represents $(\phi)^4(\frac{FFI}{BVI})^2$, n represents K_a) (Coates Model).

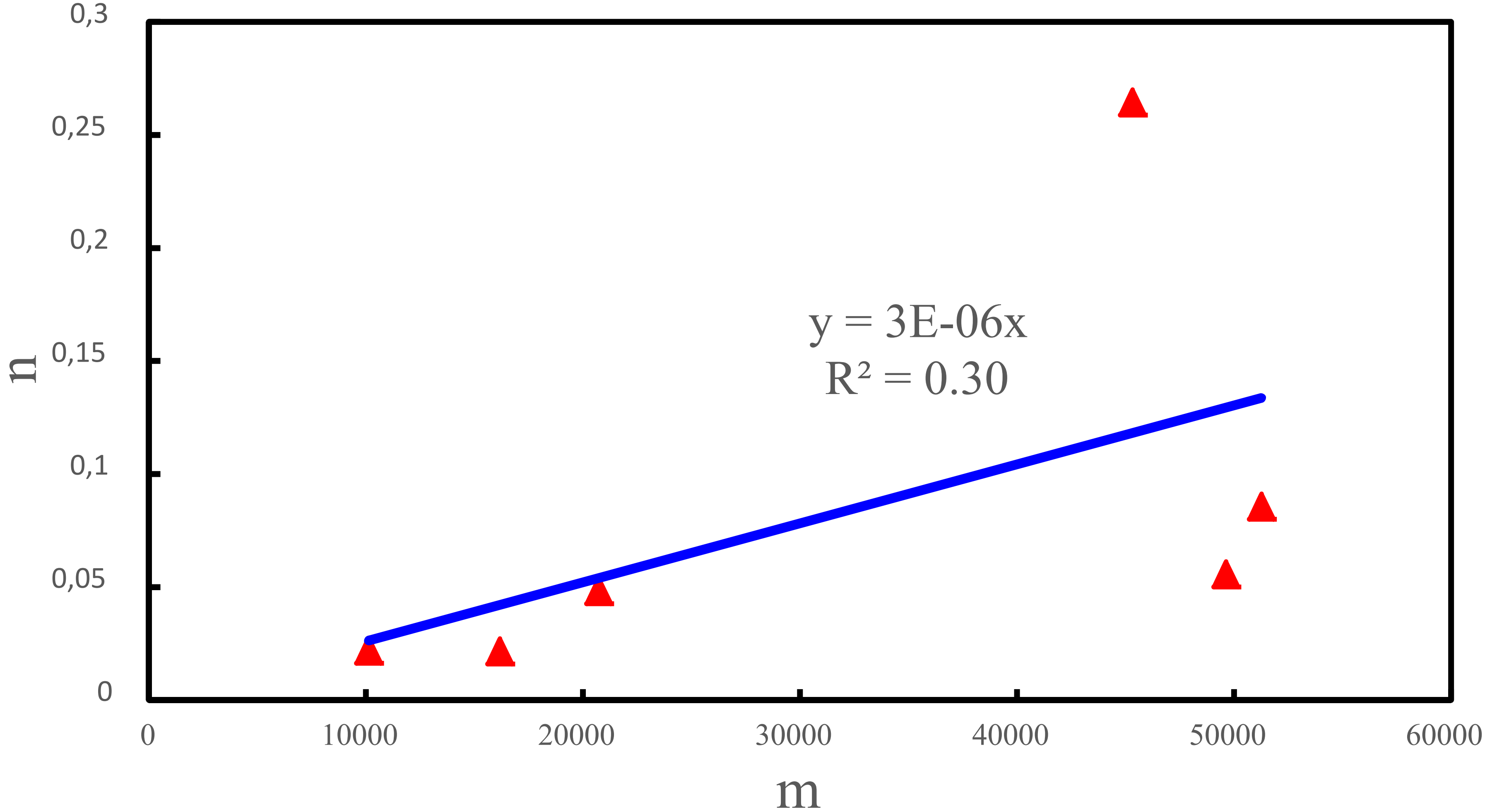

Figure 5. The regression analysis between $\phi^4 T_{2gm}{}^2$ and K_a. (m represents $\phi^4 T_{2gm}{}^2$, n represents K_a) (SDR Model).

Sample	porosity and permeability			XRD results					
	K_g (md)	φ_g (%)	φ_w (%)	Qz (wt%)	Kfs (wt%)	Pl (wt%)	Cal (wt%)	Ank (wt%)	TCCM (wt%)
302-31	0.2644	10.8	9.71	39.4	6.2	22.2	0.9	3.1	28.2
431-15	0.0856	12.36	11.97	39.2	5.8	29.2	0.6	3.2	22.0
430-10	0.0215	8.88	7.79	31.0	10.2	34.3	1.1	2.8	20.6
430-4	0.0556	8.45	7.80	30.8	12.6	31.3	1.3	3.0	21.0
430-37	0.0219	6.46	5.35	29.8	10.8	34.5	1.1	2.6	21.2
430-41	0.0482	8.65	7.65	30.5	13.4	32.2	0.8	2.7	20.4

Table 1. XRD results, porosity and permeability of sample.

F（psi）	R(μm)	Fitting formula A	R^2	Fitting formula B	R^2
21	>1	y = 0.2094x + 0.0467	0.2534	y = 0.2094x + 0.0467	0.2534
84	0.3-1	y = 0.6521x + 0.1216	0.8556	y = 0.4427x + 0.0749	0.9589
208	0.1-0.3	y = 0.7483x + 0.246	0.9634	y = 0.0963x + 0.1244	0.0514
418	0.05-0.1	y = 0.5009x + 0.3951	0.902	y = - 0.2474x + 0.1491	0.9940
696	0.03-0.05	y = 0.4351x + 0.4945	0.6656	y = - 0.0658x + 0.0994	0.1743

Table 2. The linear regression analysis results between movable fluid percentage and gas permeability.