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Article

Shale Gas Content Calculation of the Triassic Yanchang Formation in the Southeastern Ordos Basin, China

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Abstract: Shale gas content is the key parameter for shale gas potential evaluation and favorable area prediction. Therefore, it is very important to determine shale gas content accurately. Generally, we use the USBM method for coal reservoirs to calculate gas content of shale reservoirs. However, shale reservoirs are different from coal reservoirs in depth, pressure, core collection, etc. This method would inevitably cause problems. In order to make the USBM method more suitable for shale reservoir, an improved USBM method is put forward on the basis of systematic analysis of core pressure history and temperature history during shale gas desorption. The improved USBM method modifies the calculation method of the lost time, and determines the temperature balance time of water heating. In addition, we give the calculation method of adsorption gas content and free gas content, especially the new method of calculating the oil dissolved gas content and water dissolved gas content which are easily neglected. We used the direct method (USBM and the improved USBM) and the indirect method (adsorption gas, free gas and dissolved gas) to calculate the shale gas content of 16 shale samples of the Triassic Yanchang Formation in the Southeastern Ordos Basin, China. The results of the improved USBM method show that the total shale gas content is high, with an average of 3.97 m^3/t, and the lost shale gas content is the largest proportion with an average of 62%. The total shale gas content calculated by the improved USBM method is greater than that of the USBM method. The results of the indirect method show that the total shale gas content is large, with an average of 4.11 m^3/t, and the adsorption shale gas content is the largest proportion with an average of 71%. The oil dissolved shale gas content which should be taken attention accounts for about 7.8%. The relative error between the improved USBM method and indirect method is much smaller than that between USBM method and indirect method, which verifies the accuracy of the improved USBM method.

Keywords: shale gas; lost shale gas content; oil dissolved shale gas content; improved USBM method; Ordos Basin

1. Introduction

With the successful exploitation of shale gas in North America [1-3], many Chinese scholars have begun to study Chinese shale gas resources, and found that China has a huge amount of shale gas resources [4-7]. In recent years, Chinese enterprises have started industrial exploitation of shale gas in Sichuan Province and other regions, and obtained high shale gas production [8-11]. Shale gas has become one of the most popular unconventional oil and gas resources in China today [12-14]. Shale gas content is the key parameter for shale gas potential evaluation and favorable area prediction. Therefore, it is very important to determine shale gas content accurately [15-20]. So far, there is no uniform industry standard and experimental technology for measuring shale gas content. In general, shale gas content measurement methods can be divided into two types: direct method and indirect method [21, 22]. The direct method (the desorption method) determines shale gas content through direct desorption experiments of fresh shale samples on drilling site. There exists a great error in calculating the lost shale gas content when using the direct method to calculate shale gas content. Therefore, how to calculate the accurate lost shale gas content has become the research focus of the direct method.

Normally, we use the USBM method [23], Smith-Williams method [24, 25], Curve fitting method [26], etc to restore the lost shale gas content. As an industrial measurement standard for coal bed methane content in the United States and China, USBM method is widely used because of its simple operability and high accuracy. The indirect method includes methane isothermal adsorption method, log interpretation method and statistical analysis method. The adsorption shale gas content and the adsorption capacity of shale are studied by using the Langmuir model [19, 27, 28]. The log interpretation method refers to the calculation of shale gas content by using many log response characteristics [29, 30]. The statistical analysis method is to calculate the shale gas content by using the main geological factors that affect shale gas content [31, 32]. Generally speaking, the indirect method can obtain abundant information about shale gas content, thus it is the most common and accurate test method at present.

The USBM method was originally applied to coal reservoirs. However, shale reservoirs are different from coal reservoirs in depth, pressure, core collection, etc. Therefore, if applied to shale reservoirs directly, this method would inevitably cause problems. In order to make the USBM method more suitable for shale reservoirs, an improved USBM method is put forward on the basis of systematic analysis of core pressure history and temperature history during shale gas desorption. The newly improved USBM method modifies the calculation method of the lost time, and determines the temperature balance time of water heating. Meanwhile, we also give the calculation method of adsorption shale gas content and free shale gas content, especially the new method of calculating the oil dissolved shale gas content and water dissolved shale gas content that are easily neglected. We used the direct method (USBM and the improved USBM) and the indirect method (adsorption gas, free gas and dissolved gas) to calculate the shale gas content of 16 shale samples of the Triassic Yanchang Formation in the Southeastern Ordos Basin, China.

2. Experimental methods

2.1. On-site shale desorption experiments

In order to obtain accurate desorption shale gas content and residual shale gas content, on-site shale desorption experiments were conducted on 16 shale samples of the Triassic Yanchang Formation in the Southeastern Ordos Basin, China. Desorption shale gas is a gas that is desorbed from shale. Desorption shale gas content is measured on a water heating desorption instrument by means of downward drainage counts. Water heating desorption instrument includes water heating tank, desorption canister, water tank, measuring cylinder, valve, rubber tub, etc (Figure 1). The experimental process consists of three parts: waiting for core lifting, core loading and data recording. When waiting for core lifting, the temperatures of water heating tank and desorption canister have risen and then maintained to the actual formation temperature. Core loading refers to weighing these drilled shale core samples and loading them into desorption canisters as soon as possible. Data recording refers to the process of recording the cumulative desorption gas volume and desorption time. Residual shale gas is a gas remaining in the dead pores of shale. Residual shale gas content is measured on a ball

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milling machine which shatters shale samples and releases residual shale gas from shale samples. The experiment process consists of three parts: sample weighing, crushing and data recording.

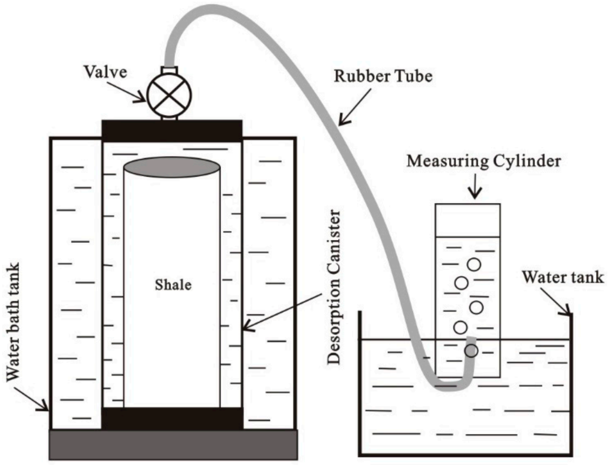

Figure 1. Composition of water heating desorption instrument.

2.2. Methane isothermal sorption measurements

In order to obtain accurate adsorption shale gas content and evaluate methane adsorption capacity of shale, methane isothermal sorption measurements were conducted on 16 shale samples of the Triassic Yanchang Formation in the Southeastern Ordos Basin, China. The methane isothermal sorption measurements were performed on FY–KT1000 isothermal adsorption apparatus adopting GB/T19560–2004 (China national standard) testing standard [33]. The experiment process consists of four parts: sample weighing, air tightness check, determination of void volume and isothermal adsorption experiment. The shale samples (110-140g) were sieved to about 80 mesh particle size and displayed humidity between 1.56% and 1.98%. The reference cell and sample cell were pressured up to 15MPa to check air tightness. Determination of void volume was measured with the inert non-sorption helium gas. We determined the amount of adsorbed methane from minimum to maximum pressure. The Langmuir volume (V_L) and the Langmuir pressure (P_L) were calculated using the Langmuir model [34].

3. Calculating methods

3.1. *Direct method*

3.1.1. Desorption shale gas content and residual shale gas content

The total shale gas content of the direct method is composed of three parts: desorption shale gas content, lost shale gas content and residual shale gas content (as shown in Equation (1)). Desorption shale gas is a gas that is desorbed from shale. Lost shale gas is a gas that escapes from shale core during core lifting. Residual shale gas is a gas remaining in the dead pores of shale. Shale gas content is the volume of gas per unit mass. From the on-site shale desorption experiments above, we could obtain desorption shale gas volume, residual shale gas volume and shale sample’s mass. Therefore, we can use Equation (2) to calculate desorption shale gas content and Equation (3) to calculate residual shale gas content. If we get lost shale gas volume, we can also use Equation (4) to calculate lost shale gas content.

$$V_{direct} = V_{desr} + V_{resi} + V_{lost} \tag{1}$$

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$$V_{desr}=\frac{v_{desr}}{m} \tag{2}$$

$$V_{resi}=\frac{v_{resi}}{m} \tag{3}$$

$$V_{lost}=\frac{v_{lost}}{m} \tag{4}$$

Where V_{direct} is the total shale gas content of direct method in m³/t, $V_{desr}$is the desorption shale gas content in m³/t, V_{resi} is the residual shale gas content in m³/t, V_{lost} is the lost shale gas content in m³/t, v_{desr} is the desorption shale gas volume in m³, v_{resi} is the residual shale gas volume in m³, v_{lost} is the lost shale gas volume in m³, and m is the mass of shale samples in t.

3.1.2. Lost shale gas content

3.1.2.1. USBM method

Based on simplified results of previous studies, Kissell and Mcculloch from the US Bureau of Mines proposed the USBM method in 1973 [**Error! Reference source not found.**]. This method is built on the principle of gas diffusion for calculating the lost gas content of coal reservoirs. The basic assumption of the method is that the rock sample is a cylindrical model; the temperature and gas diffusion rate are constant during diffusion; the surface diffusion concentration is zero at the beginning; gas diffusion process from the particle center to the surface is instantaneous. From this model, it is concluded that the cumulative desorption gas volume is linearly proportional to the square root of cumulative gas diffusion time in the early desorption process. As shown in Equation (5), the cumulative desorption gas volume and desorption time are obtained from on-site rock desorption experiments, the cumulative gas diffusion time contains lost gas time and desorption time, and the intercept of equation is the lost gas volume. Thus the least square regression method or graphic method (Figure 2) can be used to calculate the lost gas volume.

$$v_{desr}=v_{lost}+a\sqrt{t_{lost}+t_{desr}} \tag{5}$$

Where v_{desr} is the cumulative desorption gas volume in m³, v_{lost} is a negative value of the lost gas volume in m³, t_{lost} is the total lost time in minute, t_{desr} is the desorption time in minute, and a is a constant.

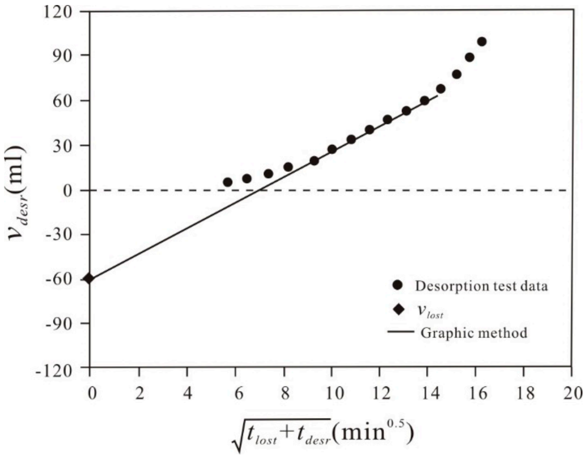

Figure 2. The determination of lost gas volume using a graphic method of USBM.

3.1.2.2. Improved USBM method

Since USBM method has a strong theoretical foundation and a reasonable mathematical deduction, it has been widely used to calculate the lost gas of coal reservoirs since 1973. This method has also been widely used to calculate the lost gas of shale reservoirs in recent years [19, 21, 35]. However, shale reservoirs are different from coal reservoirs in depth, pressure, core collection, etc. USBM method would inevitably cause problems if applied directly to shale reservoirs. In order to make the USBM method more suitable for shale reservoirs, an improved USBM method is put forward on the basis of systematic analysis of core pressure history and temperature history during shale gas desorption. The improved USBM method modifies the calculation method of the lost time, and determines the temperature balance time of water heating.

When water base mud filtrate is used to drill coal reservoirs, the total lost time of USBM method includes half of the core lifting time and exposed ground time before core is loading into the desorption canister. As a part of lost time during core lifting, half of the core lifting time has no sufficient theoretical basis. It can come true only when coal core pressure is greater than mud filtrate pressure at half of coal core lifting time and gas begins to escape from coal core. As we all know, shale core is different from coal core, thus we should rediscover the pressure equilibrium point for shale core and recalculate the lost time during shale core lifting. In order to discover an accurate pressure equilibrium point for shale core, shale core pressure history and mud filtrate pressure history were systematically analyzed. The process of on-site shale desorption experiments could be divided into three stages: lifting, exposing and desorbing (Figure 3). As shown in Figure 3, the initial mud filtrate pressure was greater than the initial shale core pressure, the mud filtrate pressure decreased linearly in the process, and shale core pressure remained constant at first and begun to decrease linearly when shale core pressure was the same as mud filtrate pressure. So the point when shale core pressure was the same as mud filtrate pressure was the true pressure equilibrium point for shale core. It was at the pressure equilibrium point that shale gas started to escape from shale core.

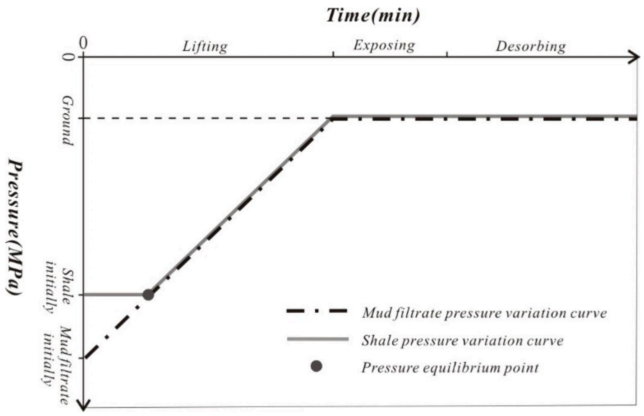

Figure 3. A systematic analysis of pressure history.

In order to identify the pressure equilibrium point quantitatively, we established a geological model of the lost shale gas during shale core lifting (Figure 4). On the basis of this model, we added several assumptions to the USBM method: (1). The initial mud filtrate pressure is greater than the initial shale core pressure. (2). The point when shale core pressure is the same as mud filtrate pressure is the true pressure equilibrium point for shale core. Above this point is shale gas lost zone, and beneath this point is shale gas seal zone. (3). Core lifting is a constant velocity process. (4). The gas dissolved in mud filtrate is neglected. Based on these assumptions, we established Equation (6), Equation (7) and Equation (8). Equation (9) could be derived from Equation (6), Equation (7) and Equation (8). As shown in Equation (10), the total lost time (t_{lost}) includes lost time during core lifting (t_{equi}) and exposed ground time (t_{expo}) before core is loading into the desorption canister. By bringing Equation (9) into Equation (10), the total lost time can be derived in Equation (11). By taking Equation (11) into Equation (5), Equation (12) can be derived. As the lost gas volume (v_{lost}) is a negative value in Equation (12), the real lost gas volume ($|v_{lost}|$) can be derived in Equation (13) by taking absolute value of lost gas volume.

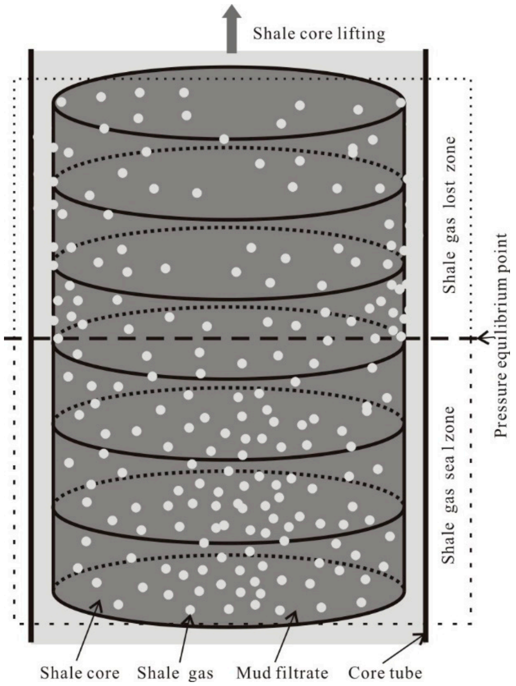

Figure 4. A geological model of the lost shale gas during shale core lifting.

$$\rho_{water} g h_{core} k = \rho_{mudf} g h_{equi} \tag{6}$$

$$h_{core} = v t_{lift} \tag{7}$$

$$h_{equi} = v t_{equi} \tag{8}$$

$$t_{equi} = \frac{\rho_{water} k t_{lift}}{\rho_{mudf}} \tag{9}$$

$$t_{lost} = t_{equi} + t_{expo} \tag{10}$$

$$t_{lost} = \frac{\rho_{water} k t_{lift}}{\rho_{mudf}} + t_{expo} \tag{11}$$

$$v_{desr} = v_{lost} + a\sqrt{\frac{\rho_{water} k t_{lift}}{\rho_{mudf}} + t_{expo} + t_{desr}} \tag{12}$$

$$|v_{lost}| = a\sqrt{\frac{\rho_{water} k t_{lift}}{\rho_{mudf}} + t_{expo} + t_{desr}} - v_{desr} \tag{13}$$

Where t_{lost} is the total lost time in minute, t_{equi} is the lost time during core lifting at the pressure equilibrium point in minute, t_{expo} is the exposed ground time before core is loading into the desorption canister in minute, t_{desr} is the desorption time in minute, t_{lift} is the core lifting time in minute, h_{core} is the depth of core in meter, h_{equi} is the depth of pressure equilibrium point in meter, v is the velocity of core lifting in m/s, ϱ_{water} is the density of water in kg/m^3, ϱ_{mudf} is the density of mud filtrate in kg/m^3, k is the formation pressure coefficient, g is the acceleration of gravity, take 9.8 m/s^2, v_{desr} is the desorption shale gas volume in m^3, v_{lost} is a negative value of the lost gas volume in m^3, $|v_{lost}|$ is the real lost gas volume in m^3, and a is a constant.

We can use Equation (11), Equation (13) and Figure 5 to analyze the difference between improved USBM method and USBM method. When $\frac{\rho_{water} kt_{lift}}{\rho_{mudf}} = 0.5$, the lost time by improved USBM method during core lifting is the same as the lost time by USBM method, and the lost gas volumes by improved USBM method and by USBM method are the same as well. When $\frac{\rho_{water} kt_{lift}}{\rho_{mudf}} > 0.5$, the lost time by improved USBM method is greater than the lost time by USBM method, and the lost gas volume by improved USBM method is greater than the lost gas volume by USBM method as well. When $\frac{\rho_{water} kt_{lift}}{\rho_{mudf}} < 0.5$, the lost time by improved USBM method is less than the lost time by USBM method, and the lost gas volume by improved USBM method is also less than the lost gas volume by USBM method. Therefore, the lost time during core lifting is determined by the density of water (ϱ_{water}), the density of mud filtrate (ϱ_{mudf}) and the formation pressure coefficient (k).

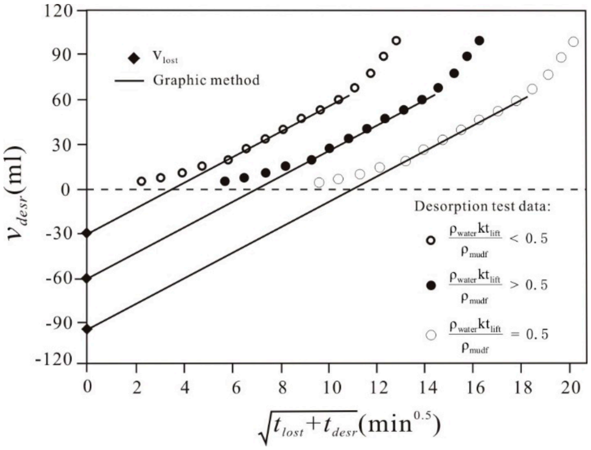

Figure 5. The calculation of lost gas volume in three types of lost time.

In order to determine the temperature balance time of water heating, shale core temperature history was systematically analyzed in Figure 6. The initial shale core temperature was the reservoir temperature. Shale core temperature was going down during lifting and remained as a constant during exposing. During desorbing, shale core temperature was heated to the reservoir temperature by water heating at first, held this temperature and eventually rose to 95 degrees centigrade. Temperature balance time is the time when shale core temperature was heated to the reservoir temperature. Desorption test data before temperature balance time could not reflect the actual desorption characteristic. Therefore these data cannot be used to calculate the lost shale gas volume and should be abandoned [**Error! Reference source not found.**, 36]. An accurate temperature balance time is important for calculation of lost shale gas volume. As shown in Figure 7, the greater the temperature balance time is, the greater the lost shale gas volume is. USBM method uses human judgment to determine temperature balance time and may cause errors in calculating the lost shale gas volume.

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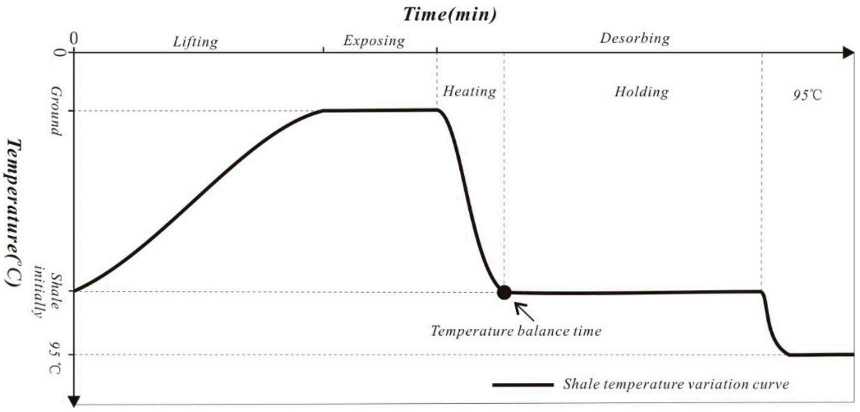

Figure 6. The temperature history of shale core.

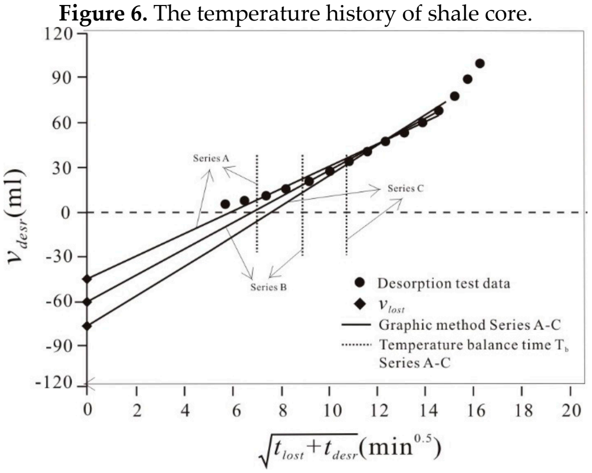

Figure 7. The calculation of lost gas volume in different temperature balance time.

To avoid human error, we use finite element analysis method to obtain an accurate temperature balance time of water heating by ANSYS software. This method allows us to determine the time at which the shale core temperature rises to reservoir temperature by water heating accurately. The process of transient thermal analysis using ANSYS software involves model building, loading, solving and post-processing. Take sample X1 as an example, mathematical model of sample X1 was built at first as shown in Figure 8 (Figure 8a), the appropriate performance parameters of sample X1 were loaded and solved then (Table 1). From the calculation results (Figure 8b), it is shown that the temperature of sample X1 reached the preset reservoir temperature (55℃) at 1100 seconds. As shown in Figure 8c, the temperature of sample X1was not balanced at 200s. As shown in Figure 8d, the temperature of sample X1 was balanced and reached to the reservoir temperature at 1100s. Therefore, 1100s is the temperature balance time of sample X1.

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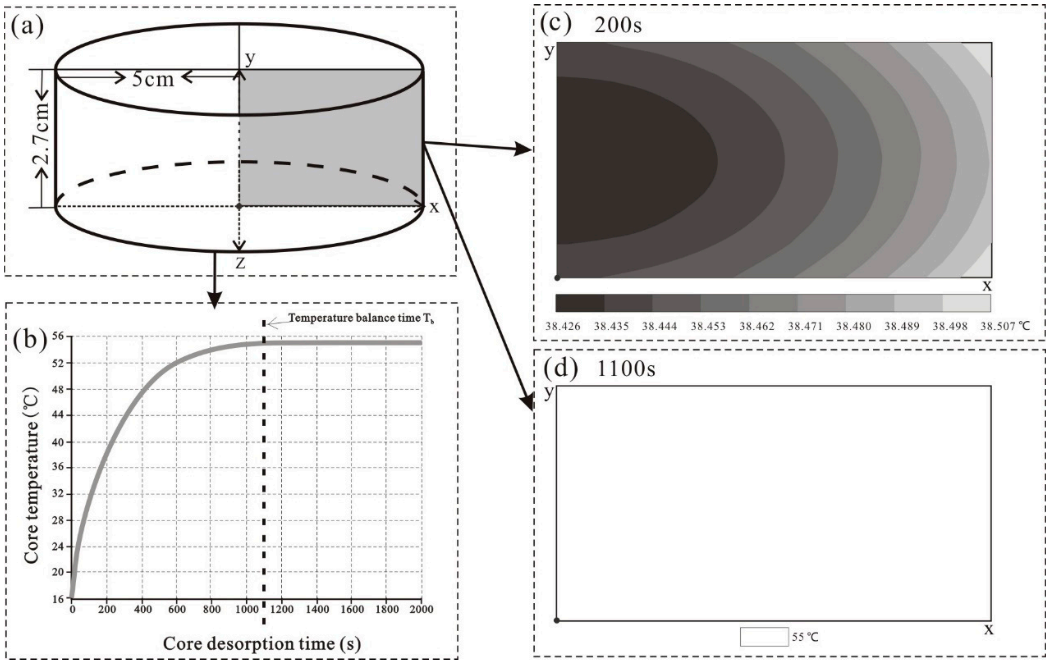

Figure 8. The process of calculating temperature balance time of sample X1 using ANSYS software.(a) Mathematical model; (b) Calculation results; (c) Temperature cloud image at 200s; (c) Temperature cloud image at 1100s.

Table 1. The performance parameters of sample X1.

Parameter	Value	Parameter	Value
Radius	5cm	Surface heat coefficient	15W/(m²·°C)
Thickness	2.7cm	Specific heat capacity	876J/kg·°C
Initial temperature	15°C	Density	2430kg/m³
Water heating temperature	55°C	Thermal conductivity	5 W/(m·°C)

3.2. Indirect method

3.2.1. Adsorption shale gas content

The total shale gas content of the indirect method is composed of three parts: adsorption shale gas content, free shale gas content and dissolved shale gas content (as shown in Equation (14)). Methane sorption measurements were conducted to obtain accurate adsorption shale gas content. As shown in Figure 9, we determined the amount of adsorbed methane from minimum to maximum pressure at reservoir temperature at first, then the Langmuir model was used to calculate the Langmuir volume (V_L) and the Langmuir pressure (P_L). At last, the Langmuir volume (V_L) and the Langmuir pressure (P_L) could be used to calculate adsorption shale gas content in Equation (15) [34, 37-40].

$$V_{indirect}=V_{adsr}+V_{free}+V_{diss} \tag{14}$$

$$V_{adsr}=\frac{V_L p}{p+P_L} \tag{15}$$

Where $V_{indirect}$ is the total shale gas content of indirect method in m³/t, V_{adsr} is the adsorption shale gas content in m³/t, V_{free} is the free shale gas content in m³/t, V_{diss} is the dissolved shale gas

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content in m³/t, V_L is the Langmuir volume in m³/t, represents the maximum methane adsorption capacity of shale at a given temperature, P_L is the Langmuir pressure in MPa, that is the pressure at half of the Langmuir volume, and p is the actual formation pressure of shale reservoir in MPa.

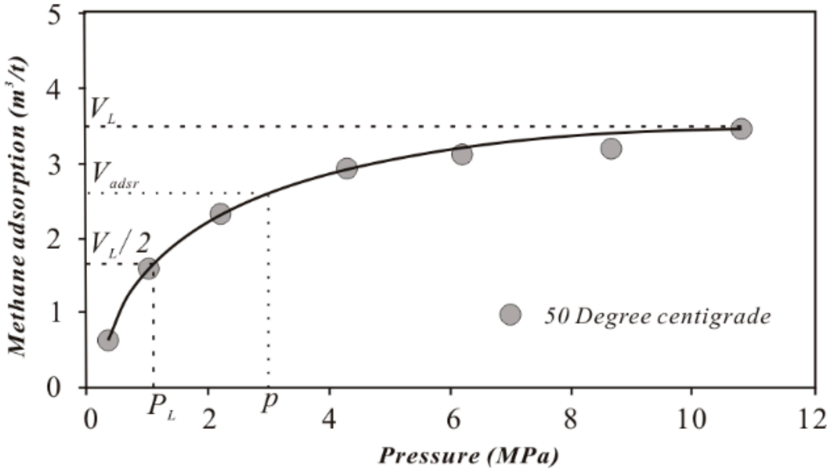

Figure 9. The calculation of adsorption shale gas content by Langmuir model.

3.2.2. Free shale gas content

As shown in Equation (16), free shale gas content is obtained by volume method [21, 41].

$$V_{free}=\frac{100\theta S_g}{\rho B_g} \qquad (16)$$

Where V_{free} is the free shale gas content in m³/t, θ is the porosity of shale core obtained by logging technique method, S_g is pore gas saturation of shale core obtained by logging technique, ρ is the density of shale core in t/m³, and B_g is the volume factor.

3.2.3. Dissolved shale gas content

The study of shale gas content mainly concentrates on adsorption shale gas content and free shale gas content. There is little research on dissolved shale gas content which is considered unimportant and negligible. However, for some reservoirs with low maturity, dissolved shale gas content has a large proportion and cannot be ignored. As shown in Equation (17), dissolved shale gas content is divided into two parts: water dissolved shale gas content and oil dissolved shale gas content. As shown in Equation (18), a new formula for calculating water dissolved shale gas content is derived by volume method in this paper. A plate method proposed by Donson and Standing [42] is used to calculate the solubility of water-soluble gas, which makes the calculation accuracy of water dissolved shale gas content very high. As shown in Equation (19), a new formula for calculating oil dissolved shale gas content is derived by the principle of similarity and dissolution in this paper. The residual hydrocarbon (S_1) is used to indicate residual oil in shale, and an empirical formula proposed by Vazquez and Beggs [43] is used to calculate the solubility of oil-soluble gas. These make the calculation accuracy of dissolved shale gas content very high.

$$V_{diss}=V_{odiss}+V_{wdiss} \qquad (17)$$

$$V_{wdiss}=\frac{\theta S_w R_{wdiss}}{\rho} \qquad (18)$$

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$$V_{odiss}=\frac{S_1R_{odiss}}{1000\rho_o} \qquad (19)$$

Where V_{diss} is the dissolved shale gas content in m³/t, V_{odiss} is the oil dissolved shale gas content in m³/t, V_{wdiss} is the water dissolved shale gas content in m³/t, θ is the porosity of shale core obtained by logging technique method, S_w is pore water saturation of shale core obtained by logging technique, ϱ is the density of shale core in t/m³, ϱ_o is the density of residual oil in t/m³, S_1 is the residual hydrocarbon in mg/g, used to indicate residual oil in shale, R_{wdiss} is the solubility of water-soluble gas in m³/m³, and R_{odiss} is the solubility of oil-soluble gas in m³/m³.

4. Results and Discussion

4.1. Direct method

As shown in Table 2, the direct method above was used to calculate shale gas content of 16 shale samples of the Triassic Yanchang Formation in the Southeastern Ordos Basin, China. Desorption shale gas content (V_{desr}) varies from 0.46 to 2.15 m³/t, with an average of 1.29 m³/t. Residual shale gas content (V_{resi}) varies from 0.08 to 0.59 m³/t, with an average of 0.24 m³/t. Lost shale gas content (V_{lost}) varies from 1.30 to 3.91 m³/t, with an average of 2.44 m³/t. The total shale gas content of direct method (V_{direct}) is from 2.17 to 5.68 m³/t, with an average of 3.97 m³/t. Therefore, shale gas content of studied area is very large by the improved USBM method.

The proportion of desorption shale gas content, residual shale gas content and lost shale gas content was analyzed in Figure 10. Lost shale gas content is the largest proportion, with an average of 62%; residual shale gas content is the smallest proportion, with an average of 6%; an average proportion of desorption shale gas content is 32%. Therefore, a large amount of shale gas is lost during shale core lifting and ground exposing.

As shown in Table 2, the results of improved USBM method and the results of USBM method were compared. Both lost time (t_{lost}) and temperature balance time (T_b) determined by improved USBM method were larger than those determined by USBM method. Both lost shale gas content (V_{lost}) and the total shale gas content (V_{direct}) determined by improved USBM method were larger than those determined by USBM method. Therefore, a large lost time and a large temperature balance time accounted for a large lost shale gas content.

Table 2. The results of shale gas content by direct method

Sample ID	Depth [m]	V_{desr} [m³/t]	V_{resi} [m³/t]	Calculating V_{lost}						V_{direct} [m³/t]	
				t_{lost}[min]		T_b [min]ᵃ		V_{lost} [m³/t]			
				USBM	Improved	USBM	Improved	USBM	Improved	USBM	Improved
X1	1336.72	0.88	0.14	177	217	12	18	0.99	1.40	2.01	2.42
X2	1409.04	0.46	0.12	262	321	14	23	1.11	1.62	1.69	2.20
X3	1419.83	1.32	0.36	342	401	8	20	1.41	2.24	3.09	3.92
X4	1392.11	1.28	0.34	227	281	12	22	1.79	2.65	3.41	4.27
X5	1390.25	1.37	0.21	240	297	10	16	2.63	3.26	4.21	4.84
X6	1400.71	2.15	0.32	188	227	14	20	1.64	2.31	4.11	4.78
X7	1338.48	1.71	0.59	264	300	10	19	1.51	2.68	3.81	4.98
X8	1346.75	1.19	0.26	183	223	9	21	1.57	2.93	3.02	4.38
X9	1456.31	0.76	0.11	231	301	11	20	0.58	1.30	1.45	2.17
X10	1387.61	1.54	0.23	198	253	12	21	2.57	3.91	4.34	5.68
X11	1466.87	1.32	0.17	212	307	7	18	1.74	2.62	3.23	4.11
X12	1478.24	1.93	0.25	277	354	8	17	0.93	1.97	3.11	4.15
X13	1354.12	1.11	0.26	241	321	14	23	1.39	2.41	2.76	3.78
X14	1423.27	1.24	0.31	331	412	12	22	1.23	2.43	2.78	3.98

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X15	1321.34	0.77	0.15	245	332	8	17	2.09	2.64	3.01	3.56
X16	1378.23	1.62	0.08	168	243	13	24	1.51	2.65	3.21	4.35

[a] T_b is the temperature balance time.

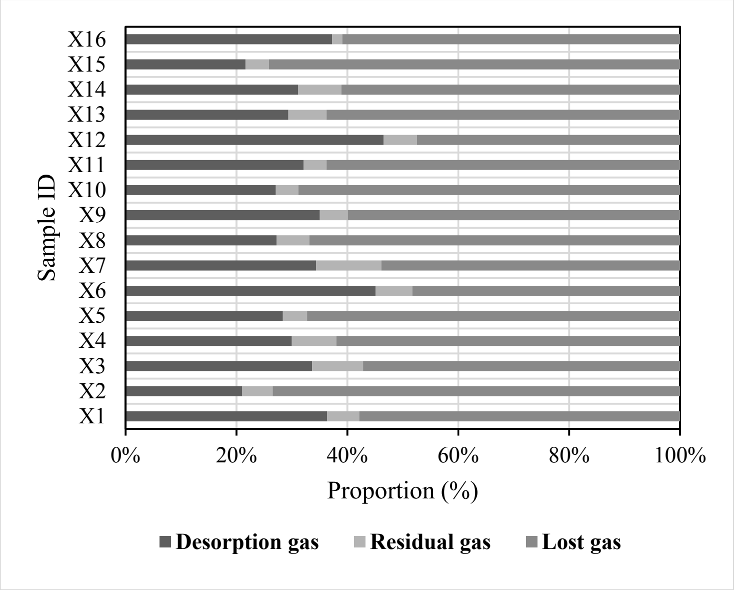

Figure 10. The proportion of desorption shale gas content, residual shale gas content and lost shale gas content.

4.2. Indirect method

As shown in Table 3, the indirect method above was used to calculate shale gas content of 16 shale samples of the Triassic Yanchang Formation in the Southeastern Ordos Basin, China. Adsorption shale gas content (V_{adsr}) ranges from 1.45 to 4.12 m³/t, with an average of 2.91 m³/t. Free shale gas content (V_{free}) varies from 0.35 to 1.42 m³/t, with an average of 0.86 m³/t. Dissolved shale gas content (V_{diss}) varies from 0.11 to 0.58 m³/t, with an average of 0.34 m³/t. The total shale gas content of indirect method ($V_{indirect}$) ranges from 1.91 to 6.02 m³/t, with an average of 4.11 m³/t. Therefore, shale gas content of this area is very high by the indirect method.

The proportion of adsorption shale gas content, free shale gas content and dissolved shale gas content were analyzed in Figure 11. Adsorption shale gas content is the largest proportion, with an average of 71%; dissolved shale gas content is the smallest proportion, with an average of 8%; an average proportion of free shale gas content is 21%. Therefore, shale is mainly adsorption shale gas in the studied area. Dissolved shale gas content is mainly oil dissolved shale gas content which accounts for about 7.8%. Oil dissolved shale gas may be caused by the low maturity of shale reservoirs in this area. Therefore, attention should be paid to oil dissolved shale gas content and water dissolved shale gas content can be neglected in this area.

Table 3. The results of shale gas content by indirect method

Sample ID	Depth [m]	V_{adsr} [m³/t]	V_{free} [m³/t]	Dissolved gas content			$V_{indirect}$ [m³/t]
				V_{odiss} [m³/t]	V_{wdiss} [m³/t]	V_{diss} [m³/t]	
X1	1336.72	1.75	0.64	0.17	0.01	0.18	2.57
X2	1409.04	1.72	0.53	0.24	0.02	0.26	2.51
X3	1419.83	3.25	0.71	0.33	0.02	0.35	4.31
X4	1392.11	2.95	0.81	0.40	0.02	0.42	4.18
X5	1390.25	3.62	1.11	0.29	0.01	0.30	5.03
X6	1400.71	3.98	0.82	0.44	0.03	0.47	5.27

X7	1338.48	3.68	0.96	0.51	0.02	0.53	5.17
X8	1346.75	2.89	0.99	0.30	0.01	0.31	4.19
X9	1456.31	1.45	0.35	0.10	0.01	0.11	1.91
X10	1387.61	4.12	1.42	0.46	0.02	0.48	6.02
X11	1466.87	2.67	0.72	0.38	0.03	0.41	3.80
X12	1478.24	3.12	1.03	0.27	0.01	0.28	4.43
X13	1354.12	1.99	0.96	0.56	0.02	0.58	3.53
X14	1423.27	3.48	0.85	0.29	0.03	0.32	4.65
X15	1321.34	2.43	0.94	0.11	0.01	0.12	3.49
X16	1378.23	3.53	0.87	0.29	0.02	0.31	4.71

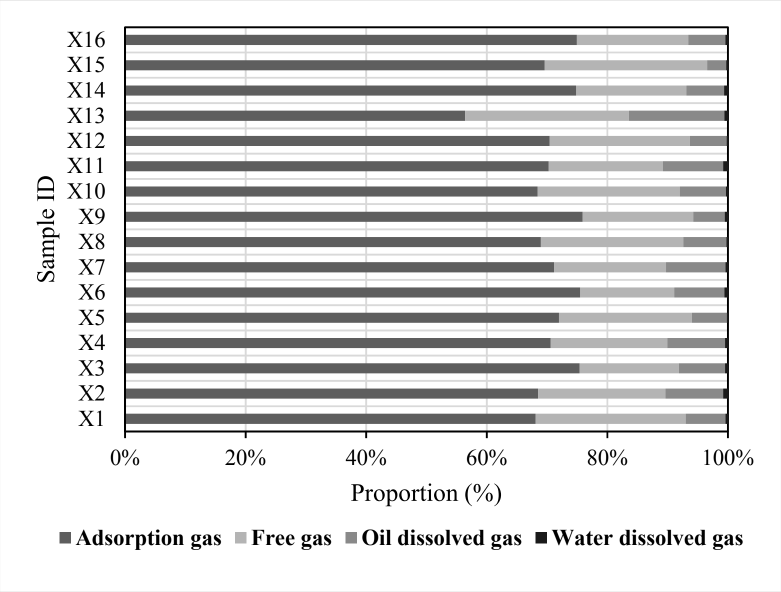

Figure 11. The proportion of adsorption shale gas content, residual shale gas content and lost shale gas content.

4.3. Comparison of two methods

On the basis of analysis above, the total shale gas content of direct method and indirect method were compared. The relative error between USBM direct method and indirect method (RE_{USBM}) was evaluated by Equation (20). The relative error between improved USBM direct method and indirect method ($RE_{Improved}$) was evaluated by Equation (21). As shown in Figure 12, The relative error between USBM direct method and indirect method (RE_{USBM}) is very large, with an average of about 24.8%. The relative error between improved USBM direct method and indirect method ($RE_{Improved}$) is very small, with an average of about 7.2%, which proves that the improved USBM method is very practical and accurate.

$$RE_{USBM} = \frac{100|V_{direct\_USBM} - V_{indirect}|}{V_{indirect}} \tag{20}$$

$$RE_{Improved} = \frac{100|V_{direct\_Improved} - V_{indirect}|}{V_{indirect}} \tag{21}$$

Where RE_{USBM} is the relative error between USBM direct method and indirect method in %, $RE_{Improved}$ is the relative error between improved USBM direct method and indirect method in %, V_{direct_USBM} is the total shale gas content of USBM method in m^3/t, $V_{direct\_Improved}$ is the total shale gas content of improved USBM method in m^3/t, and $V_{indirect}$ is the total shale gas content of indirect method in m^3/t.

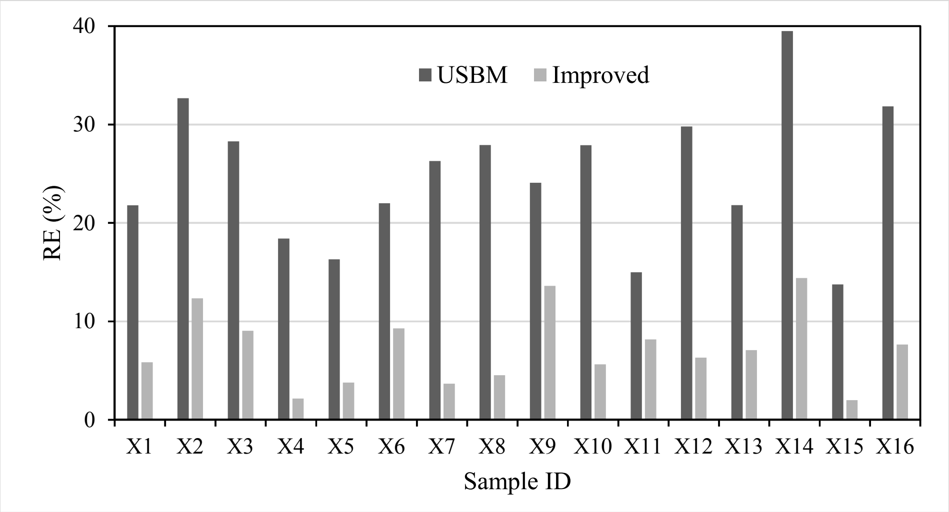

Figure 12. The relative error analysis between USBM method and improved USBM method.

5. Conclusions

(1) In order to make the USBM method more suitable for shale reservoir, an improved USBM method is put forward. On the one hand, shale core pressure history and mud filtrate pressure history were systematically analyzed to identify the pressure equilibrium point and to determine the lost gas time quantitatively; on the other hand, shale core temperature history was analyzed to obtain an accurate temperature balance time of water heating by ANSYS software. Lost time during core lifting is determined by the density of water, the density of mud filtrate and the formation pressure coefficient. Finite element analysis method allows us to determine temperature balance time accurately and avoid human error.

(2) The direct method was used to calculate shale gas content of 16 shale samples of the Triassic Yanchang Formation in the Southeastern Ordos Basin, China. Shale gas content of this area is very high by the improved USBM method, with an average of 3.97 m^3/t. Lost shale gas content is the largest proportion, with an average of 62%. Both lost shale gas content and the total shale gas content determined by improved USBM method are larger than those determined by USBM method. In the studied area, a large lost time and a large temperature balance time make a large lost shale gas content.

(3) The indirect method was used to calculate shale gas content of 16 shale samples of the Triassic Yanchang Formation in the Southeastern Ordos Basin, China. Shale gas content of this area is very high by the indirect method, with an average of 4.11 m^3/t. Adsorption shale gas content is the largest proportion, with an average of 71%. Dissolved shale gas content is mainly oil dissolved shale gas content which accounts for about 7.8%. Attention should be paid to oil dissolved shale gas content and water dissolved shale gas content can be neglected in the studied area.

(4) The total shale gas content of direct method and the total shale gas content of indirect method were compared. The relative error between improved USBM direct method and indirect method was very small, with an average of about 7.2%, which proves that the improved USBM method is very practical and accurate.

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