A method for calculating loss of shale gas during coring based on forward modeling

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Abstract
The loss of shale gas from conventional wells during coring directly affects the accuracy of measurement of shale gas content and the efficient development and utilization of shale gas. The existing methods to determine shale gas loss are not sufficiently accurate. This study used the forward modeling approach with consideration of the main influencing factors [FM (a, b)] to accurately calculate the volume of shale gas loss. Simulations of shale gas loss were run in an independently developed indoor experimental platform. A comparative analysis with established fitting methods showed that shale gas mainly exists in either a free state or an adsorbed state, and a pressure differential between the interior and exterior of the core is the primary cause of shale gas loss during coring. The FM (a, b) model simulations of shale gas loss showed reductions in average error of 16.77% and 4.6% compared to that of the improved US Bureau of Mines Method (USBM) and the curve fitting method, respectively. This study established a novel, highly accurate and widely applicable method of calculating the volume of lost shale gas.

KEYWORDS
error reduction rate, estimation model, forward modeling, shale gas, shale gas loss

1 | INTRODUCTION

The amount of shale gas lost is a function of cumulative desorption of the core during the time taken between the start and end of desorption during the core removal process (loss time). Coring of most shale gas wells is still implemented using conventional methods due to better affordability and the low success rate of pressure-holding coring technology.¹ Loss of shale gas during conventional coring can sometimes account for up to 80% of the entire shale gas yield, which
directly affects the accuracy of measurement of shale gas content and the efficient development and utilization of shale gas.\cite{2,3} Research on methods to accurately estimate shale gas loss of conventional shale gas wells during the coring process is therefore of great value.

Measurement of shale gas loss is not possible during coring, and so the loss is often estimated by inversion using desorption data after the core reaches the ground. Direct and indirect methods of estimating shale gas loss have been developed in China and internationally.\cite{4,5} Direct methods include the US Bureau of Mines (USBM) method, the improved USBM method, and the curve fitting method. The USBM method was proposed by the US Bureau of Mines for determination of shale gas loss in coal seams. Due to a short coring time, the USBM method provides a highly accurate measure of shale gas loss in a coal seam.\cite{6-8} However, since the coring duration of shale is longer, the use of the USBM method can dramatically underestimate shale gas loss.\cite{9,10} The improved USBM method is able to accurately calculate the loss duration in the shale coring process and can also optimize the initial time of shale desorption based on the core temperature and pressure histories.\cite{11-14} The curve fitting method is an accurate and highly applicable method suitable for coal reservoirs characterized by a short coring time and rich desorption data in the field.\cite{15} However, shale differs from coal seams in that it is characterized by a large proportion of free gas, deep burial, and low gas content.\cite{16-18} The direct method suffers from large inaccuracies as it uses inversion to calculate shale gas loss gas by using desorption data obtained after several hours.\cite{19} The indirect method can also be used to obtain the shale gas loss when combined with known measured desorption gas and residual gas volume. For example, the results of the isothermal adsorption test reflect the ability of shale to adsorb methane gas, which is used to evaluate the amount of adsorbed gas in shale and to determine the level of gas saturation. The logging interpretation method uses the reservoir porosity and gas saturation to calculate free gas content; however, the accuracy of the calculation of residual gas volume requires further assessment.

Since the direct method is prone to large errors due to its use of inversion using desorption data after several hours, a forward modeling approach [FM (a, b)] is proposed in the current study to calculate shale gas loss. The proposed model represents the three stages of shale coring as desorption varying with confining pressure, and excluded the influence of residual gas volume. In the experiment, four groups of shale from the Silurian Longmaxi Formation and Lower Cambrian Niutitang Formation from the eastern Sichuan Basin were selected, and an independently developed indoor shale gas loss simulation experiment platform was used to conduct shale gas loss measurement experiments.

## 2 MODEL FOUNDATION

### 2.1 Method to calculate shale gas loss based on forward modeling

#### 2.1.1 Shale coring process

During the lifting of the core to the surface, the drilling fluid pressure around the core continually decreases as the height of the drilling fluid column decreases (Figure 1). An equilibrium point is reached in the core when the drilling fluid column pressure is equal to the fluid pressure in the core. When the drilling fluid column pressure is less than the internal fluid pressure of the core, the shale core undergoes decompression and desorption until the core reaches the surface and is cleaned and canned. Shale gas loss from the shale core occurs from the equilibrium point to the end of core canning.

**FIGURE 1** Conceptual representation of the model for dispersion of lost gas during shale core extraction
The desorption quantity, or the amount of shale gas loss, cannot be measured directly during this process.

To construct the mathematical model, a series of assumptions was made about the shale coring process: (1) During the process of adsorption and desorption, the temperature and diffusion rate are constant at various points inside and outside the specimen; (2) the gas satisfies the gas state equation during the test process, and the gas concentration at the surface of the shale core at the beginning of diffusion is zero; (3) the process of shale adsorption and desorption is regarded as reversible and is a physical adsorption process; (4) shale gas is regarded as mainly occurring in the free state or the adsorbed state, ignoring the influence of dissolved gas; (5) gas diffusion from the center of the shale core to the surface is instantaneous, without considering the influence of seepage resistance in core specimens.

2.1.2 Model to calculate shale gas loss

Shale gas in a formation mainly occurs in three states, namely, a free state, adsorption state, or a dissolved state in which gas is partially dissolved in formation water. Since the proportion of gas in the dissolved state is negligible, Ambrose et al mainly considered the adsorption state and the free state.\(^{20,21}\) The pressure around the core declines during the coring process. As shown in Figure 2, gas in the adsorption state will gradually move into a free state, after which it is released from the core.

During the shale coring process, the total gas content in the core can be categorized according to the sequence of time into shale gas loss, measured desorbed gas and residual gas. According to the coring process, total gas content in core equals shale gas loss plus measured desorption gas plus residual gas.

As previously mentioned, the proportion of shale gas in a dissolved state is negligible and can be ignored. Therefore, according to the considered states of gas, total gas content in the core equals desorption gas of the adsorption state plus desorption gas of the free state.

Thus, the method to calculate the loss of shale gas during the coring process is can be represented at a high level as, shale gas loss equals desorption gas of the adsorption state plus the desorption gas of the free state minus measured desorption gas.

The residual gas is the gas desorbed by the core when the desorption pressure is less than 0.1 MPa. A decline in the desorption pressure from formation saturation pressure to atmospheric pressure in combination with the coring process eliminates the effect of residual gas volume, and therefore, shale gas loss equals the desorption gas of the adsorption state plus the desorption gas of the free state minus the measured desorption gas.

The indirect method of determining shale gas content was used to calculate the amount of desorption gas of the adsorption and free states. Using the approach outlined above, a model for calculating shale gas loss based on forward modeling was developed.

2.2 Integral desorption equation of the adsorption state

When the desorption pressure is reduced from \(p_s\) to \(p\), the amount of desorbed gas of the adsorption state in the core (the derivation process is shown in Appendix 1) is expressed as\(^{22}\):

\[
Q_{\text{adsorption desorption}} = \frac{ab(p_s - p)}{1 + bp_s} \left(\frac{1}{1 + bp}\right)
\]  

In Equation (1), \(Q_{\text{adsorption desorption}}\) is the amount of desorbed gas of the adsorption state of the core (mL) when pressure is reduced from \(p_s\) to \(p\), \(P_s\) is saturated pressure (MPa), \(P\) is the current core pressure (MPa), and \(a\) and \(b\) are constants related to the physical properties and temperature of the adsorbed gas (mL and MPa\(^{-1}\), respectively).

\[
Q_{\text{adsorption}} = \frac{abp}{1 + bp}
\]  

FIGURE 2 Comparison of different states in which gas occurs in shale cores under different confining pressures. \(p_0\) represents atmospheric pressure, and \(p_i\) represents reservoir pressure.
In Equation (2), $Q_{\text{adsorption}}$ is the cumulative adsorption of the core (mL) when the pressure is $p$. Equation (2) was changed to the following linear relationship to determine the values of the constants $a$ and $b$ in the Langmuir equation:

$$Q_{\text{adsorption}} = a - \frac{1}{b} \left( \frac{Q_{\text{adsorption}}}{p} \right)$$

In Equation (3), $a$ is the intercept of the line and $b$ is the inverse of the slope of the line.

### 2.3 Integral desorption equation of the free state

With reference to the volumetric method approach taken to calculate gas reserves, the core can be regarded as a storage tank under uniform pressure. According to the principle of conservation of mass, the material balance equation is obtained as:

$$Q_h = Q_s - Q_{\text{free release}}$$

In Equation (4), $Q_h$ is the remaining gas volume in the core under the current pressure (mL), $Q_s$ is the total volume of free gas of the core under saturation pressure (mL), and $Q_{\text{free release}}$ is cumulative free gas released from the core under the current pressure (mL).

$$Q_h B_g = Q_s B_g - Q_{\text{free release}} B_g$$

In Equation (5), $B_g$ and $B_s$ are gas volume coefficients under saturated pressure and current pressure conditions, respectively (dimensionless).

The volume coefficient is expressed as:

$$B_g = \frac{P_s Z_s T_s / P_s T_s}{P_s T_s}$$

$$B_s = \frac{P_s Z_s T_s / P_s T_s}{P_s T_s}$$

In Equation (6), $P_s$ is the ground standard atmospheric pressure (0.101325 MPa), $T_s$ is the standard temperature (273.15 K), $T_s$ is the formation temperature (K), and $Z_s$ and $Z$ are deviation coefficients under a saturated pressure (dimensionless) under current conditions, respectively (dimensionless).

A simultaneous solution of Equations (4)-(6) yields:

$$Q_{\text{free release}} = \frac{Q_s \left( (P_s / Z_s) - (P / Z) \right)}{P_s / Z_s}$$

### 2.4 Modified equation

The current study ignored oil in the reservoir as well as dissolution of shale gas in water. When the desorption pressure is reduced from $p_s$ to $p$, the total gas content of the core is divided into the sum of the desorbed gas in the free state and the desorbed gas in the adsorbed state:

$$Q_{\text{sl}} = Q_{\text{free release}} + Q_{\text{adsorption desorption}}$$

In Equation (8), $Q_{\text{sl}}$ is the total gas content when the core desorption pressure is reduced from $p_s$ to $p$ (mL).

As shown in Figures 2 and 3, adsorbed shale gas adheres to the inner surfaces of pores and occupies a certain volume of pore space. To avoid repeated calculation of adsorbed gas and free gas and improve the accuracy of the calculation of gas content, the free gas equation (Equation 7) is modified to Equation (10):

$$Q'_{\text{free release}} = \frac{(P_s / Z_s) - (P / Z)}{P_s / Z_s} \left[ Q_s - 4.2225 \times 10^{-5} \frac{\hat{M}}{\rho S B_g} \left( T_s \frac{P_s}{P + P_L} \right) \right]$$

In Equations (9) and (10), $Q'_{\text{free release}}$ is the total free gas of the core at saturation pressure considering the volume of adsorbed gas (mL), $Q'_{\text{free release}}$ is the cumulative free gas released from the core under current pressure excluding the volume of adsorbed gas (mL), $\hat{M}$ is the apparent molecular weight of natural gas (g mol$^{-1}$), $\rho_s$ is the adsorption-phase density (g mL$^{-1}$), $G_{\text{sl}}$ is the Langmuir storage capacity (mL), and $P_L$ is the Langmuir pressure (MPa).

Under the standard ground state, the gas volume can be expressed by the ideal gas state equation:

$$V_{sc} = \frac{nRT_s}{P_s}$$

In Equation (11), $V_{sc}$ is the volume of natural gas under standard ground conditions (mL), $R$ is the ideal gas constant [8.314 J (mol K)$^{-1}$], and $n$ is the amount of a substance (mol).

In a gas reservoir with pressure $P$ and temperature $T$, the volume $V$ of the equivalent amount of natural gas can be calculated from the real gas state equation:

$$V = \frac{ZnRT_s}{P}$$

In Equations (12) and (13), $V$ (mL) is the volume of natural gas under pressure $P$ (MPa) and temperature $T$ (K), $V_{core}$ is the core volume (mL), $S_c$ is gas saturation in the core (dimensionless), and $\phi$ is core porosity (dimensionless).
By combining Equations (10) and (13), the cumulative free gas released from the core under current pressure excluding the volume of adsorbed gas \( Q'_{\text{free release}} \) (mL) can be obtained as showed in Equation (14):

\[
Q'_{\text{freerelease}} = \frac{\left( P_s/Z_s \right) - (P/Z)}{P_s/Z_s} \left[ V_{\text{core}} \phi S_g \frac{T_{sc}}{P_{sc}} \frac{P_s}{Z_sT_s} - 4.2225 \times 10^{-5} \frac{M}{\rho_s B_g} \left( G_{st} \frac{p}{p+p_L} \right) \right]
\]  

(14)

2.5 Calculation of shale gas loss based on forward modeling

As mentioned previously, the current model ignores dissolved gas during the process of shale core extraction. Therefore, with reference to the considered gas states, when desorption pressure is reduced from \( p_s \) to \( p \), total gas content of the core is partitioned into the sum of the desorption amounts under the adsorption and free states. The total gas content of the shale core is partitioned into the sum of the shale gas loss and the measured desorption gas according to the time sequence:

\[
Q_{\text{adsorption desorption}} + Q'_{\text{freerelease}} = Q_{\text{lost of gas in shale}} + Q_{\text{actual desorption}}
\]

(15)

\[
Q_{\text{lost of gas in shale}} = Q_{\text{adsorption desorption}} + Q'_{\text{freerelease}} - Q_{\text{actual desorption}}
\]

(16)

In Equations (15) and (16), \( Q_{\text{actual desorption}} \) is the volume of natural gas measured after the core is filled on the ground (mL).

Combining Equations (1), (14), and (16) yields:

\[
Q_{\text{lost of gas in shale}} = \left( ab(p_s - p) \right) \left( 1 + b p_s \right) \left( 1 + b p \right) \frac{P_s/Z_s}{P_s/Z_s} + \left( P_s/Z_s \right) - (P/Z) \left[ V_{\text{core}} \phi S_g \frac{T_{sc}}{P_{sc}} \frac{P_s}{Z_sT_s} - 4.2225 \times 10^{-5} \frac{M}{\rho_s B_g} \left( G_{st} \frac{p}{p+p_L} \right) \right] - Q_{\text{measured test}}
\]

(17)

The shale gas adsorption-phase density obtained by molecular simulation of 0.33 g mL\(^{-1}\) was used to verify the adaptability and accuracy of the current novel model. The improved USBM and curve fitting methods were also applied to calculate shale gas loss to act as references. Since shale gas loss cannot be measured on-site, a simulation test platform for shale gas loss was independently established, and four groups of samples from the Silurian Longmaxi formation and the lower Cambrian Niutitang formation in the eastern Sichuan basin were selected for the model verification experiment. The shale gas loss obtained by the FM (a, b) model was compared with those obtained by the improved USBM and curve fitting methods.

3 MODEL VALIDATION

3.1 Experimental platform and methods

3.1.1 Experimental equipment

The present study independently established a simulation test platform for shale gas loss (Figures 3 and 4). The test platform comprised five parts, namely, a controlled-temperature water bath system, the main experimental system, a pressurization system, a data acquisition system, and desorption meter.

The water bath was maintained at constant temperatures ranging from 5°C to 95°C, with an accuracy of 0.02°C. The heating pipe, temperature sensor, temperature regulator, and circulating pump were set in the controlled-temperature water bath to guarantee uniformity of heating.

The main experimental system consisted of a reference tank, an adsorption tank, a temperature sensor (PR-21 series, accuracy of 0.15°C, Omega, United States), a pressure sensor (PX-409 series, Omega, United States; range 0 MPa-24.13 MPa, accuracy 0.03% of the full scale), piping, a vacuum pump, and valves, with a system pressure of 24 MPa (Figure 4A,B). The main experimental system was placed in the controlled-temperature water bath, and experimental gas entered the adsorption tank after stabilization at constant temperature and pressure in the reference tank. The temperature sensor was placed in the reference tank, and the pressure sensor was connected to the reference tank by piping. The most important functions of the main experimental system included adsorption and desorption,
creating a vacuum, calibration of free space volume, and monitoring of pressure and temperature in the adsorption tank.

Two different pressurization systems were used. Methane gas was introduced by connecting a pressure-reducing valve to a methane gas cylinder at 15 MPa. Helium gas was introduced with a Teledyne ISCO 260D double plunger booster pump, which provided a maximum pressure of 51.7 MPa. The air inlet of the ISCO pump was connected to the helium cylinder, and the air outlet was connected to the reference tank through the pipe and valve.

The data acquisition system consisted of computers, a LabVIEW virtual instrument platform, a temperature sensor (PR-21 series, accuracy of 0.15°C, Omega, United States), and a pressure sensor (PX-409 series, Omega, United States; range 0 MPa-24.13 MPa, accuracy 0.03% of the full scale).

The desorber comprised a normal pressure desorber and a variable pressure desorber with a specific pressure drop gradient with an accuracy of 0.1 mL, and with continual switching between the two.

The volumetric method used to measure the amount of gas adsorbed in the sample following a method described in the literature. The contrast channel volume and volume of free space were calibrated with helium. Reference Fluid Thermodynamic and Transport Properties Database (REFPROP) software was used to calculate the compression factors of helium and methane based on the gas state equation.

### 3.1.2 Experimental methods

Due to 90% of gas in shale gas consisting of methane, methane gas of 99.99% purity was used in the current study. Methane pressure was gradually increased from 0 MPa to 15 MPa according to reservoir pressure of the sample, with a total of seven test points and an equilibrium time of at least 24 h required to reach saturation after repeated tests for each test point. The steps followed in the experimental procedure were as follows: (1) The processed samples were installed in the adsorption tank, and the pipes and data collection system were connected. (2) A 24-h air tightness assessment of the whole system was performed using helium gas. The change in gas pressure over 24 h could not exceed 0.007 Mpa (as measured by the pressure sensor accuracy). (3) The controlled-temperature water bath was heated to and maintained at the reservoir temperature. The free space volume in the sample tank was calibrated. (4) The vacuum pump was operated for 30 min to create a vacuum around the sample in the tank. (5) Methane was injected following which the shale gas loss simulation experiment was conducted. Free space pressure under initial conditions is $P_{i-1}^{S,Eq}$. Valve 1, Valve 2, and valve 4 were opened whereas valve 5 was closed. The remaining valves were then closed (as shown in Figure 4A). The test gas was then injected into the reference tank, and valve 4 was closed, following which the pressure of the adsorption tank finally stabilized to $P_{i}^{R,F}$ at a temperature of $T$. Valve 5 was then opened, and the gas was allowed to enter the adsorption tank. The pressure at $T$ finally stabilized to $P_i^{S,Eq}$. From the gas state equation, the following can be concluded:

$$P_i^{S,Eq} V_F = Z_i^{S,Eq} n_i^{R,F} RT$$  \hspace{1cm} (18)

$$P_i^{R,F} V_R = Z_i^{R,F} n_i^{R,F} RT$$  \hspace{1cm} (19)

$$P_i^{S,Eq} (V_F + V_R) = Z_i^{S,Eq} n_i^{S,Eq} RT$$  \hspace{1cm} (20)

The sample adsorption amount $\Delta n_i^{ex}$ is:

$$\Delta n_i^{ex} = \frac{1}{m} \left( n_{i-1}^{R,F} + n_i^{R,F} - n_i^{S,Eq} \right)$$  \hspace{1cm} (21)

The gas injection volume was continuously increased within pressure ranges if 0 MPa-15 MPa during which the above calculation was repeated to obtain the complete isothermal adsorption curve of the sample. Equation (3) was used to obtain the values of parameters $a$ and $b$ required by the model.

(6) At the stage at which gas injection pressure reached a set value, the change in gas pressure over 24 hours was restricted to be within 0.007 MPa, which is the measurement sensitivity of the pressure sensor. Valve 8 was then opened, and the sample desorption test was then conducted with the desorption process time depending on the actual core removal time. After pressure was reduced to atmospheric pressure, measurement of desorption was continued, as according to the shale gas content determination method SY/T 6940-2013, until the desorption end point. The pressure, desorption volume, and desorption time of the entire process were recorded. Both the curve fitting method and the improved USBM method use the relationship between the desorption volume and desorption time when the confining pressure is 0 MPa to inversely calculate the volume of shale gas loss, while the model algorithm empirically calculates the amount of shale gas loss, using data such as $a$ and $b$ values, desorption amount and desorption time of the entire process of sample adsorption and desorption.

Model verification was conducted by comparing the volume of shale gas loss obtained by the model algorithm with the results of the improved USBM method, curve fitting method, and the total injection volume of the sample. Valve 6 could be opened to release pressure at stages during which the pressure was too high.
3.1.3 | Error analysis

Previous analyses showed that the main source of systematic error is generated by the adsorption/desorption test process. The relationships between the amount of adsorption and various factors are as follows:

\[ n^{ex} = f (P, T, V_f, V_r, Z) \] (22)

The volume of free space was calculated from the reference slot volume. The compression factor \( Z \) was calculated from \( P \) and \( T \); therefore, the volume of free space and the compression factor \( Z \) were obtained from the above error recursion formula. The error quantities of the remaining measurement parameters are shown in Table 1.

According to the error transfer formula, the following can be obtained:

\[ dn_i = \frac{dx_1}{x_1} + \frac{dx_2}{x_2} + \cdots + \frac{dx_n}{x_n} \] (23)

In Equation (23), \( dx_1 / x_1 \) is the relative error \( \beta_1 \). Equation (23) can be transformed into:

\[ dn_i = \beta_1 x_1 + \beta_2 x_2 + \cdots + \beta_n x_n \] (24)

### Table 1 | The error of the amount of adsorption by direct measurement of any parameter

| Parameter | Sensor System error |
|-----------|---------------------|
| \( P \)   | Omega Px409-3.5k-AL-XL Accuracy: 0.03% |
| \( T \)   | Omega pr-21 ±0.15°C |
| \( V_r \) | Helium gas measurement 48.62 mL ± 2.45% |

### Table 2 | Shale sample parameters (%) (1)

| Sample   | Formation | Mass (g) | Volume (mL) | Quartz | Carbonate | Clay | Other | Porosity |
|----------|-----------|----------|-------------|--------|-----------|------|-------|----------|
| core1415 | Niutitang | 280      | 125         | 52.3   | 18.2      | 14.6 | 12.03 | 4.3      |
| core1438.5| Niutitang | 185      | 72          | 58.4   | 18.6      | 12.9 | 6.2   | 5.7      |
| core1446 | Longmaxi  | 150      | 67          | 53.1   | 15.7      | 19.2 | 9.6   | 4.3      |
| core1213 | Longmaxi  | 190      | 75          | 50.1   | 19.9      | 28.1 | 4.3   | 4.6      |

### Table 2 | Shale sample parameters (2)

| Sample   | Reservoir pressure (MPa) | Reservoir temperature \( T_s \) (K) | Loss time (min) | \( S_g \) (%) | Zs | Measured desorption gas (mL g\(^{-1}\)) |
|----------|--------------------------|-----------------------------------|-----------------|----------------|----|----------------------------------------|
| core1415 | 14.15                    | 321                               | 257             | 5.5            | 0.873 | 0.54                                    |
| core1438.5| 14.385                   | 322                               | 260             | 9.4            | 0.87  | 0.71                                    |
| core1446 | 14.46                    | 299                               | 208             | 11.5           | 0.844 | 0.98                                    |
| core1213 | 12.13                    | 299                               | 211             | 9.03           | 0.845 | 0.96                                    |

In the current study, \( \beta_1 = 11.354\% \), \( \beta_2 = 2.731\% \), and \( \beta_3 = 3.826\% \).

In Equation (24), \( \beta_1 \) is the error under high pressure and \( \beta_3 \) and \( \beta_2 \) are the errors under low pressure. The calculation results shown above illustrate that the error of the high-pressure section is much larger than that of the low-pressure section when the adsorption amount is measured by the volumetric method. This can be explained by the accumulation of errors in the volumetric measurement. At the same time, under the same conditions as for the other tests, a larger adsorption/desorption in the shale gas loss test system is associated with smaller experimental error. Therefore, total adsorption/desorption can be increased by increasing the mass of the sample to reduce the experimental error.

3.1.4 | Functions of the experimental system

1. Simulate the shale gas loss during coring

The experimental system includes a vacuum, the inflatable injection experiment, the calibration of the volume of free space, and real-time temperature, pressure, and gas desorption metering. The system is able to experimentally represent the continuous decline of the confining pressure of the core over time during shale coring and can measure the amount of desorbed gas released by the core sample during this process, in other words, the shale gas loss.

2. Facilitate adsorption and desorption tests of shale samples

Within a constant temperature maintained by the water bath, the injecting of high-pressure gas into the adsorption tank and the maintenance of pressure while detecting changes
in pressure allows an isothermal adsorption test of large-scale shale samples to be conducted to obtain the isothermal adsorption curve of large-quality samples. The experimental system is able to place the sample in a vacuum and can obtain the injection volume of the sample under the original reservoir pressure and temperature.

1. Gas content measurement

The experimental system is able to obtain a measure of the amount of desorbed gas at a certain pressure drop rate for gas-containing samples. In this way, it can identify the relationship between desorption amount and time.

3.2 Sample preparation

To verify the model and to estimate the amount of shale gas loss, shale specimens were collected from the Silurian Longmaxi Formation and the Lower Cambrian Niutang Formation in the mountain area along the edge of the basin in southeastern Chongqing, the most productive shale gas area in China and one of the most promising prospects for shale gas exploration. The formation rocks of this area are mainly composed of carbonaceous shale, siliceous shale, silty shale, and lime-rich shale. The PANalytical X’pert PRO MPD instrument (Netherlands) was used for quantitative analysis of the entire rock under a test voltage of 40 kV and current of 40 mA. The X-ray copper target was used with a measurement angle range of 5° to 90°. The test results showed that the selected samples were representative of shale samples in the area (Table 2).

A Chinese MacroMR12-150H-I nondestructive NMR system for rock-core imaging and analysis was employed to measure gas saturation and pore size distribution of the sample to obtain its porosity. Before conducting Nuclear Magnetic Resonance (NMR), the shale specimens needed water saturation treatment lasting 12 hours to fill pores with fluid containing H in the form of H2O. The pore size distribution curves and parameters of all shale samples are shown in Figure 5 and Table 2.

(a) Schematic diagram demonstrating the experimental setup of the shale gas loss simulation experiment.

(b) Photograph showing the actual shale gas loss simulation experiment system used in the current study.
The size of the adsorption tank used in the experiment was approximately ∅60 × 120 mm. The cylindrical sample with dimensions of ∅50 × 100 mm and its shale was crushed into particles of a diameter of ~1 cm for comparative experiments. Although the results showed a large difference in adsorption time between the two, the final adsorption amount was almost equal. Due to the fact that shale is very dense, irregular shale particles with a diameter of ~1 cm were selected as the experimental sample to reduce the effect of seepage resistance, save time, and increase the feasibility of the experiment. Next, we will focus on the influence of seepage resistance.

Since no standard for assessment of shale particle adsorption exists, the current study followed the method for determining coalbed methane GB/T 35210.1-2017.34 Samples were placed into a drying box at 95°C for 24 hours. To prevent undesirable physical and chemical changes resulting from atmospheric oxidation, the samples were kept sealed in plastic bags after cooling. According to SY/T 6940-2013,28 the measurements of site-based coring parameters such as reservoir pressure and reservoir temperature are provided in Table 2.

3.3 The improved USBM method

1. Shale gas loss equation

The improved USBM method assumes that2 (1) the rock sample is cylindrical; (2) the temperature and diffusion rates are constant during diffusion; (3) the surface concentration at the beginning of diffusion is zero; (4) gas diffusion from the center of the shale core to the surface is instantaneous; and (5) \( W/W_\infty < 0.5 \), where \( W \) is the volume of desorbed gas at time \( t \) and \( W_\infty \) is the total volume of desorbed gas.

From the improved USBM method, the following is derived:

\[
Q_d = Q_0 + k\sqrt{t + t_0}
\]  

(25)

In Equation (25), \( Q_d \) is the total desorption capacity (mL), \( Q_0 \) is shale loss gas (mL), \( t_0 \) is the time when loss of gas occurs during coring (min), \( t \) is the measured desorption time (min), and \( k \) is the slope obtained by linear regression of the initial data of desorption.

1. Calculation of timing of gas loss during coring

As shown in Figure 1, during core extraction, the pressure equilibrium occurs when the wellbore pressure equals the pressure inside the core, which is the point at which shale gas starts to escape during the coring process. Therefore, the key to determining the time at which gas loss from the shale core occurs is to identify the moment of pressure equilibrium. A detailed field analysis of the pressure history of a shale core allowed the establishment of a geological model for shale gas loss during drilling under some basic assumptions. An established mathematical equation was used to determine the time at which shale gas loss occurs in the field coring process. The basic assumptions are as follows2: (1) The slurry column pressure at the beginning of coring is greater than the fluid pressure in the core. (2) During the process of core extraction, a pressure equilibrium occurs when the slurry column pressure is equal to the fluid pressure inside the core. Gas starts to escape when pressure exceeds the equilibrium point, whereas gas is confined when pressure is under the pressure equilibrium point, and the fluid pressure inside the core is maintained at the initial pressure before the equilibrium, as shown in Figure 1. (3) The core lifting speed is constant. (4) Gases dissolved in mud are ignored.

Based on these assumptions, a mathematical model of pressure equilibrium (Equations 26 and 27) was established. This model was then used to calculate the time at which loss of gas from the shale core occurs during coring (Equation 28). The final calculation equation (Equations 29) could then be obtained7:

\[
p_1g h_1 s = p_2 g h_2
\]  

(26)

\[
h_1 / t_1 = h_2 / t_2
\]  

(27)

\[
t_2 = t_1 \rho_1 s / \rho_2
\]  

(28)

\[
t_0 = t_1 \rho_1 s / \rho_2 + t_3
\]  

(29)

In Equations (26)-(29), \( t_0 \) is the loss time (min), \( t_1 \) is the drilling time (min), \( t_2 \) is the loss time during the drilling process (min), \( t_3 \) is the surface exposure time (min), \( h_1 \) is the...
depth of the shale core (m), \( h_2 \) is the depth of the pressure equilibrium (m), \( \rho_1 \) is the density of formation water (kg m\(^{-3}\)), \( \rho_2 \) is the density of drilling mud (kg m\(^{-3}\)), and \( s \) is the formation pressure coefficient.

### 3.4 Curve fitting

The curve fitting method fits the on-site desorption amount and desorption time, and combines the loss time of the core to obtain an expression that matches it, so as to obtain the loss of shale gas, as shown in Figure 6.

### 4 RESULTS AND DISCUSSION

#### 4.1 Shale gas loss calculated by the model

Values for the unknown parameters \( a \) and \( b \) in the model and a determination of the total injected gas volume of the sample were required. An isothermal adsorption test of the sample under a reservoir temperature corresponding to the core sample was conducted, and the pressure was gradually increased from the vacuum to reservoir pressures. Seven points were selected for each sample, and the equilibrium time for each pressure point was determined as 24 hours after repeated experiments. The gas injection amount corresponding to each pressure adsorption equilibrium point was calculated according to Equations (18)-(21). As shown in Figure 7, the isothermal adsorption curve of the sample at reservoir temperature and the total gas injection volume of the sample corresponding to the reservoir pressure were obtained.

Second, the total injected gas volumes of the samples corresponding to the reservoir pressure and temperature were obtained from Figure 6 and are outlined below.

The total injected gas volume of sample 1415 was:

\[
Q_{1415\text{max}} = A \ln x + B = 0.631 \times \ln 14.15 + 0.821 = 2.39 \text{ (mL/g)}
\]  

(30)

The total injected gas volume of sample 1438.5 was:

\[
Q_{1438.5\text{max}} = A \ln x + B = 0.821 \times \ln 14.385 + 0.806 = 3.0 \text{ (mL/g)}
\]  

(31)

The total injected gas volume of sample 1446 was:

\[
Q_{1446\text{max}} = \text{Intercept} + B_1 x + B_2 x^2 + B_3 x^3 = 0.412 + 0.374 \times 14.46 - 0.02 \times 14.46^2 + 5.457 \times 10^{-4} \times 14.46^3 = 3.42 \text{ (mL/g)}
\]  

(32)

The total injected gas volume of sample 1213 was:

\[
Q_{1213\text{max}} = \text{Intercept} + B_1 x + B_2 x^2 + B_3 x^3 = 0.329 + 0.532 \times 12.13 - 0.044 \times 12.13^2 + 0.0017 \times 12.13^3 = 3.34 \text{ (mL/g)}
\]  

(33)

The total injected gas volumes of the cores 1415, 1438.5, 1446, and 1213 corresponding to the reservoir pressure and temperature were 2.39, 3.0, 3.42, and 3.34 mL g\(^{-1}\), respectively.

Third, the values of parameters \( a \) and \( b \) required by the model were obtained by linear fitting according to the adsorption data in Figure 7, with \( a \) being intercept and \( b \) the negative value of the slope, as shown in Figure 8.

The data of the coring section of the reservoir indicated that the formation pressure coefficient is 1, the temperature gradient is 2°C per 100 m, and the drilling fluid density is 1.1 g mL\(^{-1}\).

The corresponding gas saturation of the sample was obtained by the NMR test, and the temperature and pressure of the sample were used along with the REFPROP software to obtain the corresponding deviation coefficient. Under the same conditions, the shale gas loss values of the four samples

---

**FIGURE 6** Calculation diagram of shale gas loss

**FIGURE 7** Isothermal adsorption curves of the shale cores obtained from the Longmaxi and the lower Cambrian Niutitang Formations
selected from the mountain area along the edge of the basin were obtained using the model developed in the current study and were compared to the results obtained by the improved USBM algorithm.

Each parameter was substituted into the model to obtain shale gas loss in each core. The shale gas loss values in cores 1415, 1438.5, 1446, and 1213 were 1.78, 2.27, 2.21, and 2.21 mL g\(^{-1}\), respectively.

### 4.2 Shale gas loss obtained by the improved USBM method

As shown in Table 2, the reservoir pressures and temperatures obtained for cores 1415, 1438.5, 1446, and 1162 were 14.15 MPa and 321 K, 14.385 MPa and 322 K, 11.46 MPa and 299 K, and 11.62 MPa and 299 K, respectively, and the corresponding loss times calculated by the Equations (20-23) were 257, 260, 208, and 211 minutes, respectively.

Using the established experimental platform, the sample was injected with methane gas. After repeated tests, the sample reached saturation at an adsorption equilibrium time of the sample of 24 hours.

The decompression desorption experiment then commenced. Measurement of desorption gas volume was initiated when the pressure in the adsorption tank was equal to atmospheric pressure. The relationship between the desorption amount and time and the shale loss time obtained in Table 2 were used as input to the improved USBM method to calculate the volume of lost gas, as shown in Figure 9. According to the improved USBM method, the shale gas loss values in cores 1415, 1438.5, 1446, and 1213 were 1.53, 1.92, 1.74, and 1.86 mL g\(^{-1}\), respectively.

### 4.3 Shale gas loss obtained by the curve fitting

Using the established experimental platform, the sample was injected with methane gas. After repeated tests, the sample reached saturation at an adsorption equilibrium time of the sample of 24 hours. The decompression desorption experiment was then initiated. Measurement of desorption gas volume was started when the pressure in the adsorption tank was equal to atmospheric pressure. The relationship between the desorption amount and time and the shale loss time obtained in Table 2 were used as input parameters within the polynomial fitting method to obtain the volume of lost gas, as shown in Figure 10. According to the polynomial fitting method, the shale gas loss values in shale cores 1415, 1438.5, 1446, and 1213 were 1.53, 1.92, 1.74, and 1.86 mL g\(^{-1}\), respectively.
1.74, 2.14, 2.19, and 2.08 mL g⁻¹, respectively.

Results of model evaluation

The residual gas contents of the samples were first obtained by ball milling, with the residual gas contents of cores 1415, 1438.5, 1446, and 1213 being 0.02, 0.01, 0.04, and 0.04 mL g⁻¹, respectively. The total gas contents of the samples were obtained by combining the measured desorption gas and the shale gas loss.

The total shale gas loss of cores 1415, 1438.5, 1446, and 1213 calculated by the FM (a, b) model were: 1.79, 2.28, 2.25, and 2.25 mL g⁻¹, respectively.

The total gas contents of cores 1415, 1438.5, 1446, and 1213 calculated by the improved USBM method were 1.53, 1.92, 1.74, and 1.86 mL g⁻¹, respectively.

The total gas contents of cores 1415, 1438.5, 1446, and 1213 calculated by the curve fitting method were 1.74, 2.14, 2.19, and 2.08 mL g⁻¹, respectively.

The total injected gas volumes of cores 1415, 1438.5, 1446, and 1213 were 1.85, 2.29, 2.44, and 2.38 mL g⁻¹, respectively.

Second, the shale gas contents obtained by the two methods were compared with the total amount injected into the sample. As shown in Table 3 and Figure 11, as compared with the improved USBM method, the FM (a, b) model achieved error reduction rates for the cores 1415, 1438.5, 1446, and 1213 of 14.05%, 15.62%, 20.9%, and 16.39%, respectively, whereas compared with the curve fitting method.

TABLE 3

| Sample     | Total injection (mL g⁻¹) | Total shale gas loss obtained by the FM (a, b) model (mL g⁻¹) | Total shale gas loss obtained by the improved USBM method (mL g⁻¹) | Error reduction rate (%) | Shale gas loss obtained by curve fitting method (mL g⁻¹) | Error reduction rate (%) |
|------------|-------------------------|---------------------------------------------------------------|---------------------------------------------------------------|--------------------------|----------------------------------------------------------|--------------------------|
| core1415   | 1.85                    | 1.79                                                          | 1.53                                                          | 1.53                     | 1.74                                                     | 14.05                    |
| core1438.5 | 2.29                    | 2.28                                                          | 1.92                                                          | 1.92                     | 2.14                                                     | 15.72                    |
| core1446   | 2.44                    | 2.25                                                          | 2.25                                                          | 2.25                     | 2.19                                                     | 20.9                     |
| core1213   | 2.38                    | 2.25                                                          | 1.86                                                          | 1.86                     | 2.08                                                     | 16.39                    |

FIGURE 11 Comparison of the results of total gas contents obtained by the forward model developed in the current study [FM (a, b)], the improved US Bureau of Mines (USBM) method, and the curve fitting method.
method, the FM (a, b) model achieved error reduction rates of 2.7%, 6.11%, 2.46%, and 7.14%, respectively. These results show that the FM (a, b) model obtained estimates of shale gas loss that were closer to the total injection volumes of the samples and that the FM (a, b) model therefore had higher accuracy.

The improved USBM method and curve fitting method both use the desorption data obtained after the core to the surface. In this way, the amount of shale gas loss can be calculated in conjunction with the loss time. However, both of the methods are bound to be inaccurate due to the relatively long shale core removal time and low gas content. The calculation of the forward model is based on pressure changes during the core lifting process, and it can be concluded that the forward model results were more in line with experimental data results and sample physical properties. Therefore, the model calculated amount of shale gas loss should be close to the observed shale gas loss of the sample.

5 | CONCLUSIONS

The current study used four groups of shales from the Silurian Longmaxi Formation and the Lower Cambrian Niutang Formation in the eastern Sichuan Basin for shale gas loss measurement experiments. Estimates of shale gas loss by the FM (a, b) method, the improved USBM method, and curve fitting method were compared to the total volumes of gas injected into the samples as a measurement of accuracy. The following conclusion can be drawn from the results:

1. The current study established a forward modeling method [FM (a, b)] by excluding the influence of residual gas volume and considering the main factors influencing shale gas loss. In contrast with the improved USBM method, the FM (a, b) model does not need to satisfy the linear relationship between the desorption amount and the square root of the desorption time at the initial stage of desorption and the model also has a wider scope of application. The FM (a, b) model also does not need to back calculate the desorption amount. Theoretically, this model is more accurate and convincing that the established fitting methods.

2. The present study independently developed an indoor shale gas loss simulation experimental platform by considering three stages of shale well core removal, namely, ground exposure, water bath heating, and desorption that changes with confining pressure.

3. The comparative analysis of the fitting methods showed that shale gas mainly exists in either a free state or an adsorbed state, and the pressure difference between the inside and outside of the core is the main driver of shale gas loss during the coring process.

4. Compared with the improved USBM method, the FM (a, b) method achieved error reduction rates of 1415, 1438.5, 1446, and 1213 of 14.05%, 15.62%, 20.9%, and 16.39%, respectively, whereas compared with the curve fitting method, the FM (a, b) model achieved error reduction rates of 2.7%, 6.11%, 2.46%, and 7.14%, respectively. These results show that the FM (a, b) model achieved estimates of volume of shale gas loss that were closer to the total volume of gas injected into the sample and that therefore the FM (a, b) model had higher accuracy.

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**APPENDIX 1**

From reference22:

\[ v = \frac{abp}{1 + bp} \]  

(I)

The saturated cumulative Langmuir adsorption amount under the saturated adsorption pressure \( P_s \) can be written as:

\[ v_s = \frac{abp_s}{1 + bp_s} \]  

(II)

The cumulative desorption amount when the pressure drops from \( P_s \) to pressure \( P \) is expressed as:

\[ Q_{\text{adsorption desorption}} = v_s - v \]  

(III)

Substituting formula (I) and formula (II) into formula (III), the cumulative desorption amount of the adsorbed state equation is:

\[ Q_{\text{adsorption desorption}} = \frac{ab(p_s - p)}{(1 + bp_s)(1 + bp)} \]  

(IV)

In Equations (I-IV), \( Q_{\text{adsorption desorption}} \) is the amount of desorbed gas of the adsorption state of the core (mL) when the pressure is reduced from \( p_s \) to \( p \). \( P_s \) is saturated pressure, (MPa), \( P \) is current core pressure (MPa), and \( a \) and \( b \) are constants related to the physical properties and temperature of the adsorbed gas (mL and MPa\(^{-1}\), respectively).