Tight Gas Reservoir Dynamic Reserve Calculation with Modified Flowing Material Balance Method

Jie He  
Northwest University

Xiangdong Guo  
Yanchang Oilfield Oil and Gas Exploration Company

Hongjun Cui  
Yanchang Oilfield Oil and Gas Exploration Company

Kaiyu Lei  
Yanchang Oilfield Oil and Gas Exploration Company

Yanyun Lei  
Yanchang Oilfield Oil and Gas Exploration Company

Lin Zhou  
Northwest University

Qinghai Liu  
Northwest University

Yushuang Zhu (petroleum_gas@163.com)  
Northwest University

Linyu Liu  
Northwest University

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Tight gas reservoir dynamic reserve calculation with modified flowing material balance method

Jie He\textsuperscript{1}, Xiangdong Guo\textsuperscript{2}, Hongjun Cui\textsuperscript{2}, Kaiyu Lei\textsuperscript{2}, Yanyun Lei\textsuperscript{2}, Lin Zhou\textsuperscript{1}, Qinghai Liu\textsuperscript{1}, Yushuang Zhu\textsuperscript{1}, Linyu Liu\textsuperscript{1}

\textsuperscript{1}. State Key Laboratory of Continental Dynamics/Department of Geology, Northwest University, Xi’an, 710069, China; \textsuperscript{2}. No. 1 Gas Production Plant, Yanchang Oilfield Oil and Gas Exploration Company, Yan’an 716000, China; Corresponding author: Yushuang Zhu, Professor, Doctoral Supervisor, Northwest University, China. E-mail address: petroleum_gas@163.com.

Abstract: The determination of dynamic reserves of gas well is an important basis for rational production allocation and development of a single well. The commonly used flow material balance method (FMB method) uses the slope of the curve of wellhead pressure and cumulative production after stable production of gas well to replace the slope of the curve of average formation pressure and cumulative production to calculate the controlled reserves of single well. However, based on the theoretical calculation, the FMB method ignores the change of natural gas compression coefficient, viscosity and deviation coefficient in the production process. After considering these changes, the slope of the curve of the relationship between bottom hole pressure and cumulative production and the slope of the curve of the relationship between average formation pressure and cumulative production are not equal. In order to solve this problem, the influence of pressure on each parameter is considered, and the equation of modified flowing material balance method is derived. The application of Yan’an gas field in Ordos Basin shows that: compared with the results of the material balance method, the result of the flow material balance method is smaller, and the maximum error is 58.816%. The consequence of the modified mobile material balance method is more accurate, and the average error is 2.114%, which has good applicability. This study provides technical support for an accurate evaluation of dynamic reserves of tight gas wells in Yan'an gas field, and has important guiding significance for economic and efficient development of gas reservoir.

Keywords: Dynamic reserve; Flowing material Balance; Tight gas reservoir; Yan’an Gas field; Ordos Basin
Yan'an gas field, located in the southeast of Yishan slope in Ordos Basin, is a typical tight sandstone gas reservoir with the characteristics of low permeability, strong heterogeneity, strong stress sensitivity and complex percolation mechanism (Li and Qiao, 2012). Pressure measurement and variable production often occur in the process of production test and development, so it is difficult to calculate the dynamic reserves of gas wells in this gas field.

At present, the main methods for calculating dynamic reserves including material balance method, the production decline method, production accumulation method, elastic two-phase method and so on (Chen and Che, 2011; Shults, 2020). Among them, the establishment of the material balance method is relatively easy, and only needs high-pressure property data and production data, the calculation method is relatively simple (Cheng et al., 2005; Yang et al., 2019). Therefore, this method has become a commonly used one for dynamic analysis of gas reservoirs and is widely used in various gas reservoirs at home and abroad.

When there is no data such as bottom hole pressure, the material balance method cannot calculate the dynamic reserves of gas wells. In order to solve this problem, Mattar put forward the flowing material balance method, which is analyzed from the point of view of percolation mechanics (Yang et al., 2019; Yin et al., 2019). For a closed gas reservoir, after the gas well is produced relatively stable for a certain period of time, the pressure wave is transmitted to the outer boundary of the formation, and gas seepage enters a pseudo steady state (Huang et al., 2015). As showed in the figure (Fig. 1), the pressure drop curve will be some parallel curves, and the formation pressure drop is almost equal to the bottom hole flow pressure drop in the same period of time (He et al., 2019). When gas wells are produced with stable production, there is a stable conversion relationship between bottom hole flow pressure and wellhead casing pressure, Mattar et al proposed that wellhead casing pressure and bottom hole flow pressure replace formation pressure in generalized material balance respectively:

$$\frac{P_i}{Z} = \frac{P_{ci}}{Z_i}\left(1-\frac{G_p}{G}\right)$$  \hspace{1cm} \text{Formula (1)}
The flowing material balance method does not take into account the effect of pressure on the viscosity and compression coefficient of gas, that is, it is considered that the viscosity and compression coefficient of natural gas remain unchanged (Yu et al., 2012). However, when the formation pressure of the reservoir is low and the production pressure difference is large, the assumption is not valid, so there is an error in the calculation (Han et al., 2019; Zhang et al., 2013b; Zhong et al., 2012).

In order to solve the above problems, a modified FMB method is proposed in this study, in which the influence of pressure on the viscosity and compression coefficient of gas is considered, and the modified flowing material balance equation is derived. Taking the tight gas reservoir in Yanchang Oilfield in Ordos Basin as an example, the flow material balance method before and after correction is compared and analyzed, and the accuracy of the modified flow material balance method is verified.

1 Method

1.1 Property of natural gas

1.1.1 Viscosity of natural gas

The viscosity of natural gas is different from that of liquid. Under the condition of low pressure, the viscosity of natural gas increases with the increase of temperature (Yao et al., 2015). However, when the pressure is greater than 10MPa, the viscosity of natural gas decreases at first and then increases with the increase of temperature. However, whether under low pressure or high pressure, the viscosity of natural gas increases with the increase of pressure. When there is non-hydrocarbon gas in natural gas, the viscosity often increases.
The experimental determination of natural gas is difficult, so reservoir engineers usually use relevant empirical formulas to calculate (Wei et al., 2017). Through 10 natural gas samples (Table 1) under the condition of temperature 352 K and pressure 30MPa, the viscosity is calculated, and the pressure-viscosity diagram is drawn based on the calculated results, as showed in figure (Fig. 2).

### 1.1.2 Deviation coefficient of natural gas

The deviation coefficient of natural gas refers to the ratio of the real volume to the ideal volume of the same mass gas under a certain temperature and pressure (Wei et al., 2017). Through the data of 10 gas samples, we can get the relationship between Z at different temperatures, as showed in figure (Fig. 3). When the pressure is lower than 15MPa, Z decreases with the increase of pressure, and then increases with the increase of temperature.

\[
Z = \frac{V_{actual}}{V_{ideal}}
\]

![Fig. 2 P-μ curve of natural gas](image1)

![Fig. 3 P-Z curve of natural gas](image2)

### 1.1.3 Compression coefficient of natural gas

The compression coefficient of natural gas refers to the change of unit volume with pressure under the condition of constant temperature (Nie et al., 2018). For ideal gas, \(Z=1\), therefore, \(C_g=1/P\) (Zhang et al., 2013a).

\[
C_g = -\frac{1}{V} \left( \frac{\partial V}{\partial P} \right)_T
\]

According to the data of 10 samples, the relationship of P~Cg at different temperatures can be obtained, as showed in figure (Fig. 4): the compression coefficient of gas decreases with temperature and pressure, and is less affected by temperature.

### 1.1.4 Volume coefficient of natural gas
The volume of natural gas is measured under the surface standard conditions, so it is necessary to convert the volume of natural gas measured under the surface conditions to the volume under the formation conditions (LIU, 2009; Nie et al., 2018). This conversion coefficient is the volume coefficient of natural gas. The volume coefficient of natural gas is defined as the actual volume occupied by a certain molar amount of gas under formation conditions, divided by the volume occupied by the same molar amount of gas underground standard conditions, the calculation formula is as follows:

\[ B_g = \frac{V_R}{V_{sc}} \]

According to the data of 10 samples, the relationship of \( P-\text{Bg} \) at different temperatures can be obtained, as shown in figure (Fig. 5): the volume coefficient of natural gas decreases with the increase of pressure and increases with the increase of temperature.

Table. 1 Composition analysis data of 10 groups of natural gas samples

| Gas composition | Sample |
|-----------------|--------|
|                 | 1  | 2  | 3  | 4  | 5  | 6  | 7  | 8  | 9  | 10 |
| C1              | 95.04 | 95.96 | 95.18 | 94.45 | 95.41 | 95.72 | 95.62 | 95.31 | 96.00 | 96.06 |
| C2              | 0.47  | 0.59  | 0.44  | 0.53  | 0.45  | 0.49  | 0.68  | 0.55  | 0.50  | 0.55 |
| C3              | 0.03  | 0.07  | 0.03  | 0.03  | 0.03  | 0.03  | 0.05  | 0.04  | 0.04  | 0.04 |
| n-C4            | 0.03  | 0.07  | 0.05  | 0.04  | 0.05  | 0.03  | 0.16  | 0.13  | 0.12  | 0.13 |
| i-C4            | 0     | 0.007 | 0     | 0     | 0     | 0     | 0     | 0     | 0     | 0   |
| n-C5            | 0     | 0     | 0     | 0     | 0     | 0     | 0     | 0     | 0     | 0   |
| i-C5            | 0     | 0     | 0     | 0     | 0     | 0     | 0     | 0     | 0     | 0   |
| C6              | 0     | 0     | 0     | 0     | 0     | 0     | 0     | 0     | 0     | 0   |
| C7+             | 0     | 0     | 0     | 0     | 0     | 0     | 0     | 0     | 0     | 0   |
| CO₂             | 3.84  | 2.68  | 3.66  | 4.33  | 3.06  | 2.83  | 3.04  | 3.34  | 2.83  | 2.63 |
| He              | 0     | 0     | 0     | 0     | 0     | 0     | 0     | 0     | 0     | 0   |
| H₂              | 0     | 0     | 0     | 0     | 0     | 0     | 0     | 0     | 0     | 0   |

Fig. 4 P-Cg curve of natural gas

Fig. 5 P-Bg curve of natural gas
|     | H₂S | 0   | 0   | 0   | 0   | 0   | 0   | 0   | 0   | 0   |
|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|
| N₂  | 0.589 | 0.621 | 0.641 | 0.624 | 1.01 | 0.902 | 0.56 | 0.725 | 0.596 | 0.679 |
| O₂  | 0   | 0   | 0   | 0   | 0   | 0   | 0   | 0   | 0   | 0   |
| Relative density (T=20°C) | 0.60 | 0.59 | 0.60 | 0.59 | 0.59 | 0.59 | 0.59 | 0.59 | 0.59 | 0.59 |
| Density (T=20°C)(kg/m³) | 0.72 | 0.71 | 0.72 | 0.73 | 0.71 | 0.71 | 0.71 | 0.71 | 0.71 | 0.71 |
| Low calorific value (T=20°C)(MJ/kg) | 44.63 | 46.01 | 44.81 | 44.03 | 45.23 | 45.60 | 45.61 | 45.12 | 45.84 | 46.02 |
| High calorific value (T=20°C)(MJ/kg) | 49.54 | 51.06 | 49.73 | 48.87 | 50.20 | 50.61 | 50.62 | 50.09 | 50.88 | 51.08 |
| Total | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.00 | 100.11 | 100.09 | 100.08 | 100.09 |

### 1.2 FMB method

For the gas reservoir produced by circular, closed and central vertical well, when the development stage enters the pseudo steady state, it can be obtained (Xin et al., 2018):

\[
\frac{\partial (P/u_c Z)}{\partial G_p} = \frac{\partial (P_{wf}/u_{gwf} c_{gwf} Z_{wf})}{\partial G_p}
\]

Formula (3)

In the FMB method, it is assumed that the pressure has no effect on the viscosity and compression coefficient of natural gas, that is:

\[
\partial (u_c c_g) = \partial (u_{gwf} c_{gwf})
\]

Formula (4)

And then get:

\[
\frac{\partial (P/Z)}{\partial G_p} = \frac{\partial (P_{wf}/Z_{wf})}{\partial G_p}
\]

Formula (5)

Therefore, when the gas reservoir reaches pseudo steady state, \( P/Z \) : \( G_p \) is parallel to \( P_{wf}/Z_{wf} : G_p \) in Cartesian coordinate system. According to the \( P_{wf}/Z_{wf} \) and \( G_p \) data in production, the data points showing a straight line trend are fitted, and then a parallel line is made through the \( P/Z \) point, and the intercept of the parallel line on the \( G_p \) coordinate is the dynamic reserve \( G_i \).

### 1.3 Modified FMB method

According to the experimental data, the composition and experimental conditions of gas are shown in the table (Table. 1) as shown. The experimental results are shown in figures (Fig. 2, Fig. 3, Fig. 4, Fig. 5). It can be seen that the viscosity, compression coefficient and deviation factor of natural gas change obviously with pressure.
The relationship between $\mu g C_g$ and pressure can be obtained from the experimental data. As shown in figure (Fig. 6), it can be seen that the hypothetical formula (4) is not valid, that is, the viscosity and compression coefficient of natural gas vary with pressure.

As can be seen from the figure (Fig. 6):

$$\frac{\partial (u_g C_g)}{\partial P} < \frac{\partial (u_{gwf} C_{gwf})}{\partial P}$$

Formula (6)

Combined with the formula (3), (6), and then get:

$$\frac{\partial (\bar{P}/\bar{Z})}{\partial G_p} < \frac{\partial (P_{wf}/Z_{wf})}{\partial G_p}$$

Formula (7)

It can be seen that the absolute value of the slope of the $P_{wf}/Z_{wf}$ : $G_p$ line is greater than that of the $\bar{P} / \bar{Z}$ : $G_p$ line, and the lower the formation pressure is, the greater the production pressure difference is, and the greater the difference between them is.

Therefore, reserves determined by the FMB method are smaller than the real reserves. In order to reduce the calculation error of gas well reserves, the FMB method must be modified.

By deforming the formula (3), and then get:

$$\frac{\partial (\bar{P}/\bar{Z})}{\partial G_p} = \frac{\partial (u_g C_g)}{\partial (u_{gwf} C_{gwf})} \frac{\partial (P_{wf}/Z_{wf})}{\partial G_p}$$

Formula (8)

It is assumed that in any short period at the initial stage of pseudo steady state, $\bar{P}_{pss}$
and $P_{\text{wff-pss}}$ represent the average formation pressure and bottom hole flow pressure at the initial stage of pseudo steady state, respectively, $\lambda = \partial (\bar{u}_g c_g) / \partial (u_{	ext{gwf}}c_{	ext{gwf}})$. In the pseudo steady state, the average formation pressure and bottom hole flow pressure decrease at the same speed, so it can be considered that $\lambda$ remains basically unchanged. At the same time, $\lambda$ can be calculated by the $P_{\text{wff-pss}}$ values of $u_g c_g$ and $\bar{P}_{\text{pss}}$ at the initial stage of pseudo steady state. In addition, after the gas well starts production, it will soon reach a pseudo steady state, so there is little difference between the original formation pressure and the average initial formation pressure $\bar{P}_{\text{pss}}$ of the pseudo steady state. In the pseudo steady state, $\lambda$ can be calculated from the following formula:

$$\frac{\partial (\bar{u}_g c_g)}{\partial (u_{\text{gwf}} c_{\text{gwf}})} \approx \left( \frac{u_g c_g}{P_{\text{wff}}} \right)_{p_{\text{f-pss}}} \approx \left( \frac{u_g c_g}{P_f} \right)_{P_{\text{f-pss}}} = \lambda$$  \hspace{1cm} (Formula 9)

And then get:

$$\frac{\partial (P/Z)}{\partial G_p} = \lambda \frac{\partial (P_{\text{wff}}/Z_{\text{wff}})}{\partial G_p}$$

Based on the above process, application steps of the modified FMB method are as follows (Fig. 7).

(1) according to the $p : u_g c_g$ relation curve, $\left( \frac{u_g c_g}{p_i} \right)_{p_{i-pss}}$ and $\left( \frac{u_g c_g}{P_{\text{f-pss}}} \right)$ are determined, the formula (3-13) is determined, and the R is calculated.

(2) using the bottom hole flow pressure and cumulative production data, draw the $P_{\text{wff}}/Z_{\text{wff}} : G_p$ curve, linearly fit the data points showing a linear trend, and determine the fitting straight line slope $-m$.

(3) calculate the $-\lambda m$, and take this slope as the slope and make a straight line over $P_i/Z_i$, and the intercept of the straight line on the Abscissa is the reserves determined by the modified FMB method (modified $G_i$).

(4) similarly, the wellhead casing pressure $P_i$ is used to replace the bottom hole flow...
3 Result

3.1 Geological background

Ordos basin is a large sedimentary basin with multi-cycle evolution and multi-sedimentary types (Hu and Zhai, 2010). The area of the basin is about 25×10^4 km^2. At present, the structure is a large syncline with slow width in the east and steep and narrow in the west, and the dip angle is generally less than 1° (Li et al., 2012; Li et al., 2013). Fault folds in the margin of the basin are well developed and the internal structure is relatively simple (Liu, 2012). There is no secondary structure in the basin, and the tertiary structure is dominated by nose uplift, and there are few anticline structures with large amplitude and good trap (LIU, 2009). According to the current structural shape, basement properties and structural characteristics of the basin, the Ordos basin can be divided into six first-order structural units: Yimeng uplift, Weibei uplift, western Shanxi flexure fold belt, Yishan slope, Tianhuan depression and western margin thrust structural belt (Peng and Zhao, 2013).

Yan'an gas field is located in the southeast of Yishan slope in Ordos basin, as shown in figure (Fig. 8) (Yang et al., 2012). The comprehensive geological study shows that the Upper Paleozoic in the study area has many favorable conditions, such as extensive hydrocarbon generation, development of reservoir rock multi-layer system, wide distribution of regional caprock and so on, which are beneficial to the formation and enrichment of large lithologic gas reservoirs (Wang et al., 2011; Wang et al.,...
A total of 689 gas wells in the study area are divided into three types according to the results of gas test data, and their productivity is evaluated respectively: type I wells (open flow rate > 10.0×10^4 m^3/d), type II wells (open flow rate 4.0~10.0×10^4 m^3/d) and class III wells (open flow rate less than 4.0×10^4 m^3/d). The classification results are shown in the table (Table. 2)(Lu et al., 2019; Sun et al., 2021; Wang et al., 2017):

3.2 Calculation results of type I wells

The initial production of type I wells in Yan'an gas field is high, the pressure drops slowly, and the stable production time is long, so it has a good stable production capacity under the condition of low pressure.

S-4 well is a typical type I well in Yan 128 high pressure well area, and the open flow rate of gas test is 26.57×10^4m^3/d. It has been in production since August 2013. From the production curve (Fig. 9), it can be seen that at the initial stage of production (August 2013 to April 2015), the average monthly production of gas wells is 64×10^4m^3/m, and the water production is at a low level, with an average monthly production of 4.28m^3/m, and the water-gas ratio is maintained at 0.066 (m^3/10^4m^3). In the second stage of production (May 2015 to April 2017), the casing pressure
decreases rapidly, the oil pressure decreases rapidly, and the monthly water production is higher, and the monthly gas production decreases rapidly. In the third stage of production (May 2017 to April 2020), the monthly gas production and monthly water production are kept at a low level, casing pressure is about 7MPa, and the oil pressure is about 8MPa. Up to now, the cumulative gas production of S-4 well is \(3633.775 \times 10^4\text{m}^3\) and the cumulative water production is \(356.67\text{m}^3\).

Using production data and wellhead casing pressure, draw \(P_c/Z_c\sim G_p\) curve, as shown in figure (Fig. 10). The linear fitting is carried out for the data points showing a straight line trend, and the slope of the straight line is \(-0.0024\). The slope of the straight line passes through the \(P_i/Z_i\) point as a straight line, and the intercept on the Abscissa is \(0.8737 \times 10^8\text{m}^8\), which is the dynamic reserve of S-4 well determined by the FMB method.

The calculation results show that \(-\lambda=-0.6387\), \(-\lambda_m=-0.0015\). Taking \(-\lambda_m\) as the slope and making a straight line through the \(P_i/Z_i\) point, the intercept on the Abscissa is \(1.3980 \times 10^8\text{m}^8\), which is the dynamic reserve of well S-4 determined by the modified FMB method.

### 3.3 Calculation results of type II wells

The test production of type II wells in the study area is between \(4.0 \times 10^4\text{m}^3/d\) and \(10.0 \times 10^4\text{m}^3/d\), and the pressure drops rapidly, accounting for 20.048% of the number of wells in the whole area.

S-5 well is a typical type II well in Yan 128 high pressure well area (Fig. 11). 190 days of trial production operation was carried out in S-5 well from November 19, 2009 to May 27, 2010, and 70 days of pressure recovery test was carried out from May 27 to
August 7, 2010. The open flow rate of gas test in this well is $4.7045 \times 10^4$ m$^3$/d, and the original formation pressure is 25.872 MPa. The production starts at $1.5 \times 10^4$ m$^3$/d. Due to the large pressure fluctuation in the trial production process, the gas production is difficult to be stable, and the working system is adjusted, the daily gas production is gradually reduced to about $1 \times 10^4$ m$^3$/d, and the daily water production is 0.1~1.8 m$^3$/d. After the gas production is reduced to $1 \times 10^4$ m$^3$/d, the oil pressure decreases from 14.41MPa to 12.36MPa, a decrease of 2.05 MPa, and the oil pressure decreases at a rate of 0.051MPa/d, which shows that the production is basically stable. Up to April 2020, the cumulative gas production is $3471.62 \times 10^4$ m$^3$ and the cumulative water production is 490.25m$^3$.

Using production data and wellhead casing pressure, draw $P_c/Z_c$~$G_p$ curve, as shown in figure (Fig. 12). The linear fitting is carried out for the data points showing a straight line trend, and the slope of the straight line is -0.0026. The slope of the straight line passes through the $P_i/Z_i$ point as a straight line, and the intercept on the Abscissa is $0.8065 \times 10^8$ m$^8$, which is the dynamic reserve of S-5 well determined by the FMB method.

The calculation results show that $\lambda=-0.704$, $\lambda_m=-0.0018$. Taking $\lambda_m$ as the slope and making a straight line through the $P_i/Z_i$ point, the intercept on the Abscissa is $1.1650 \times 10^8$ m$^8$, which is the dynamic reserve of well S-5 determined by the modified FMB method.

### 3.4 Calculation results of type III wells

The initial production of type III wells in the study area is low, about $35 \times 10^4$ m$^3$/m, and the current production is $20 \times 10^4$ m$^3$/m. It has a certain stable production capacity.
under the condition of low pressure. If the allocation of production is reduced, it can be produced steadily for a long time.

S-6 well is a typical type III well in this area, and the open flow rate of gas test is $8.944 \times 10^4 \text{m}^3/\text{d}$. It has been in production since June 2013. From the production curve (Fig. 13), it can be seen that at the initial stage of production (June 2013 to December 2014), the average monthly production of gas wells is $50 \times 10^4 \text{m}^3/\text{m}$, the water production is at a low level, the average monthly production is $3.02 \text{m}^3/\text{m}$, and the water-gas ratio is maintained at 0.060 ($\text{m}^3/10^4 \text{m}^3$). In the second stage of production (from January 2015 to June 2018), the casing pressure decreased rapidly and the monthly gas production remained unchanged. In the third stage of production (July 2018 to April 2020), the monthly gas production decreases rapidly, the monthly water production increases rapidly, the casing pressure is kept at about 8.5MPa, and the oil pressure is maintained at about 7.8MPa. Up to now, the cumulative gas production of S-6 is $2580.92 \times 10^4 \text{m}^3$, and the cumulative water production is $237.55 \text{m}^3$.

Using production data and wellhead casing pressure, draw $P_c/Z_c$--$G_p$ curve, as shown in figure (Fig. 14). The linear fitting is carried out for the data points showing a straight line trend, and the slope of the straight line is -0.0031. The slope of the straight line passes through the $P_i/Z_i$ point as a straight line, and the intercept on the Abscissa is $0.6765 \times 10^8 \text{m}^8$, which is the dynamic reserve of S-6 well determined by the FMB method.

The calculation results show that $-\lambda=-0.667$, $-\lambda_m=-0.0021$. Taking $-\lambda_m$ as the slope and making a straight line through the $P_i/Z_i$ point, the intercept on the Abscissa is $0.9986 \times 10^8 \text{m}^8$, which is the dynamic reserve of well S-6 determined by the modified
4 Discussion

Compared with the FMB method, the material balance method uses the average formation pressure data measured after shut-in for a long time, so its calculation result is more real and reliable (Fan et al., 2012; GAO et al., 2009).

4.1 Method verification

In order to verify the accuracy of the calculation results of the modified FMB method, as shown in the table (Table 3), using the measured formation pressure at different stages of the production of the three wells, the scatter diagram between the cumulative gas production and the measured Pzag Z is drawn (Fig. 15, Fig. 16, Fig. 17). By linear fitting these discrete data points, the dynamic reserves of single well calculated by three kinds of well material balance method can be obtained (Xu et al., 2014; Xu et al., 2016). ① The dynamic reserve of single well in S-4 is 1.3849×10⁸m³ calculated by material balance method. By comparing the above calculation results, the error of FMB method is 36.91%, and the error of modified FMB method is 0.95% (Table 4, Fig. 18). ② The dynamic reserve of single well in S-5 is 1.1864×10⁸m³ calculated by material balance method. By comparing the above calculation results, the error of FMB method is 32.02%, and the error of modified FMB method is 1.80% (Table 4, Fig. 18). ③ The dynamic reserve of single well in S-6 is 1.0086×10⁸m³ calculated by material balance method. By comparing the above calculation results, the error of FMB method is 32.93%, and the error of modified FMB method is 1.00% (Table 4, Fig. 18).

Through the above calculation results (Fig. 18), compared with the material balance method, the calculation result of the FMB method is generally small, with an average error of 33.95%; the error of the modified FMB method is small, with an average of 1.25% (Li et al., 2018). Therefore, it can be concluded that when there is a lack of measured pressure data, the calculation result of the modified FMB method is more accurate than that of the FMB method.

| Time | S4       | S5       | S6       |
|------|----------|----------|----------|
|      |          |          |          |

Table 3 Measured pressure in three wells
Three dynamic reserve methods are used to calculate 31 typical gas wells in the study area, and the results are shown in the table (Table. 5). The average reserves calculated by the material balance method and the FMB method are $1.2731 \times 10^8 \text{m}^3$ and $0.6794 \times 10^8 \text{m}^3$, respectively. The minimum error is 28.499%, the maximum is 58.816%, and the average is 44.536%. The average error of the modified FMB...
method is $1.3008 \times 10^8 \text{m}^3$, the minimum error is 1.290%, the maximum value is 3.063%, and the average is 2.114%. It is worth noting that the single wells with large errors in the calculation results of the modified FMB method are S-56 and S-60-1.

Combined with the production data of two wells, S-56 well was put into production in June 2013 (Fig. 19), and the shut-in state appeared intermittently from June 2013 to December 2016, the pressure recovery state was in a short time, which reflected that the formation pressure and casing pressure drop in the early stage of production were relatively small, and the gas production per unit pressure drop was relatively large (Mattar et al., 2006). Because there is no intermittent shut-in in the later stage of production, the law of monthly gas production verifies this theory. Therefore, it can be concluded that the early shut-in leads to the large dynamic reserves of a single well. Similarly, the S-60-1 well was put into production in July 2015 (Fig. 20), and the intermittent shut-in occurred in the later stage of production, and the production law of the gas well could not fully reflect the real state of the gas well, resulting in a large calculation error.

It can be seen that the great change in the production system of gas wells will affect the accuracy of the calculation results of the modified FMB method, especially the shut-in for a long time before calculating the pressure drop gas production at a certain time. Therefore, time data points with relatively stable production should be selected as far as possible to calculate the dynamic reserves of a single well.

Table 5  Calculation results of three dynamic reserve methods

| WELL | Initial wellhead casing pressure(MPa) | Pseudo steady wellhead casing pressure(MPa) | MBA Reserves ($10^4 \text{m}^3$) | Mobile MBA Reserves ($10^4 \text{m}^3$) | Error(%) | Modified Mobile MBA Reserves ($10^4 \text{m}^3$) | Error(%) |
|------|-------------------------------------|------------------------------------------|---------------------------------|---------------------------------|---------|---------------------------------|---------|
| S1   | 15.8462                             | 12.8592                                  | 7153.74                         | 4282.75                         | 40.133% | 7342.40                         | 2.637%  |
| S12  | 17.1079                             | 13.4597                                  | 14160.04                        | 6336.27                         | 55.252% | 14370.62                        | 1.487%  |
| S14  | 18.7003                             | 12.8507                                  | 10602.13                        | 5843.84                         | 44.881% | 10833.20                        | 2.179%  |
| S15  | 17.3198                             | 14.2056                                  | 12111.63                        | 8659.90                         | 28.499% | 12334.85                        | 1.843%  |
| S16  | 18.0042                             | 14.2344                                  | 12881.02                        | 6668.23                         | 48.232% | 13183.31                        | 2.347%  |
| S18  | 20.9695                             | 14.9531                                  | 9300.99                         | 5114.52                         | 45.011% | 9482.64                         | 1.953%  |
| S19  | 19.1588                             | 13.4765                                  | 15158.98                        | 7982.84                         | 47.339% | 15426.74                        | 1.766%  |
| S2   | 16.6048                             | 12.7247                                  | 4488.28                         | 2515.88                         | 43.946% | 4560.57                         | 1.611%  |
| S20  | 20.9194                             | 15.9530                                  | 23281.23                        | 11621.87                        | 50.081% | 23693.58                        | 1.771%  |


|   |   |   |   |   |   |
|---|---|---|---|---|---|
| S23 | 17.2632 | 12.3611 | 18463.87 | 11508.79 | 37.669% | 18979.53 | 2.793% |
| S24 | 17.8761 | 13.3496 | 8295.53 | 4831.38 | 41.759% | 8488.67 | 2.328% |
| S3  | 15.3464 | 11.4357 | 4419.17 | 3009.09 | 31.908% | 4498.07 | 1.785% |
| S36 | 18.4218 | 14.2318 | 9857.57 | 5070.29 | 50.733% | 14547.33 | 2.222% |
| S37 | 15.3464 | 12.7981 | 17870.36 | 10961.70 | 38.660% | 18146.58 | 1.546% |
| S40 | 16.4099 | 11.9387 | 7545.85 | 3907.11 | 48.222% | 7699.04 | 2.030% |
| S41 | 20.8429 | 15.2572 | 8776.13 | 4631.75 | 47.223% | 8951.42 | 1.997% |
| S42 | 20.1747 | 15.6005 | 14231.18 | 9857.57 | 30.733% | 14547.33 | 2.222% |
| S47 | 15.4740 | 11.0778 | 9600.02 | 5951.53 | 38.005% | 9782.98 | 1.906% |
| S48 | 18.1943 | 13.0624 | 10857.71 | 6273.89 | 41.993% | 11010.45 | 1.801% |
| S53 | 16.5886 | 14.4144 | 3164.75 | 1987.80 | 37.259% | 3217.64 | 1.433% |
| S56 | 17.5138 | 14.1972 | 7124.17 | 4230.08 | 40.623% | 7339.25 | 3.019% |
| S60 | 22.6343 | 17.3155 | 12818.85 | 7636.40 | 37.534% | 12994.22 | 1.290% |
| S60-1| 23.8290 | 15.3464 | 14704.97 | 7073.23 | 51.899% | 15155.41 | 3.063% |
| S8  | 17.9103 | 13.5156 | 62126.78 | 25586.07 | 58.816% | 63747.11 | 2.608% |
| Y170| 17.9788 | 14.2530 | 16910.98 | 11236.74 | 53.254% | 17356.94 | 2.637% |
| Y185| 19.8759 | 13.2931 | 2211.32 | 1129.31 | 48.930% | 2257.58 | 2.092% |
| Y196| 18.4994 | 10.9542 | 19046.76 | 9736.50 | 49.829% | 19839.12 | 2.228% |
| Y202| 18.1875 | 13.3156 | 8538.40 | 4208.89 | 50.706% | 8750.41 | 2.483% |
| Min | 15.3464 | 10.9542 | 2211.32 | 1129.31 | 28.499% | 2257.58 | 1.290% |
| Max | 23.8290 | 17.3155 | 62126.78 | 25586.07 | 58.816% | 63747.11 | 3.063% |
| Average | 18.3638 | 13.6973 | 12730.33 | 6794.81 | 44.536% | 13008.37 | 2.114% |

Fig. 19 S-56 well production curve
Fig. 20 S-60-1 well production curve

5 Conclusion

(1) Yan'an gas field is characterized by low permeability and strong heterogeneity. A total of 689 gas wells in the study area are divided into three types according to the results of gas test data, and their productivity is evaluated respectively: type I wells (open flow rate > 10.0×10^4 m^3/d), type II wells (open flow rate 4.0~10.0×10^4 m^3/d)
and class III wells (open flow rate less than $4.0 \times 10^4 \text{m}^3$/d).

(2) Through theoretical calculation and numerical simulation, it is found that the viscosity of natural gas increases rapidly with the increase of pressure, the compression coefficient of natural gas decreases at first ($P<15\text{MPa}$) and then increases with the increase of pressure ($P>15\text{MPa}$), and increases with the increase of temperature. Under the condition of low pressure, the compression coefficient and volume coefficient of natural gas decrease rapidly with the increase of pressure and increase with the increase of temperature.

(3) Considering the viscosity, compression coefficient and deviation coefficient of natural gas, the FMB method is modified, and the calculation method and steps are given at the same time.

(4) Verified by the production data of three types of typical gas wells, the results show that compared with the calculation results of the material balance method, the average error of the FMB method is 33.95%, and the average error of the modified FMB method is 1.25%.

(5) The new method is used to calculate the dynamic reserves of 31 gas wells in the study area. The results show that the great change of the production system of gas wells will affect the accuracy of the modified FMB method, especially the shut-in for a long time before the pressure drop gas production is calculated at a certain time, so the points with relatively stable production should be selected as far as possible to calculate the dynamic reserves of a single well.

Remarks

$Z$: Deviation coefficient of natural gas;

$V_{\text{actual}}$: The volume of a real gas, m$^3$;

$V_{\text{ideal}}$: The volume of ideal gas, m$^3$;

$C_g$: Natural gas compression coefficient;

$B_g$: Volume coefficient of natural gas;

$V_R$: Underground volume of natural gas, m$^3$;

$V_{\text{sc}}$: Volume of natural gas under surface conditions, m$^3$;

$P_c$: Wellhead casing pressure, MPa;
\( P_\text{c} \): Original wellhead casing pressure, MPa;

\( P_{\text{wf}} \): Bottom hole flow pressure, MPa;

\( P_{\text{wf,i}} \): Original bottom hole flow pressure, MPa.

\( G_p \): Cumulative gas production, \( 10^4 \text{m}^3 \);

\( \bar{P} \): Average formation pressure, MPa;

\( p_{\text{wf}} \): Bottom hole flow pressure, MPa;

\( \bar{Z} \): Deviation coefficient of natural gas under average formation pressure;

\( Z_{\text{wf}} \): Deviation coefficient of natural gas under bottom hole flow pressure;

\( \bar{u}_g \): Viscosity of natural gas under average formation pressure, mPa·s;

\( u_{\text{gwf}} \): Viscosity of natural gas under bottom hole flow pressure, mPa·s;

\( \bar{C}_g \): Compression coefficient of natural gas under average formation pressure, MPa\(^{-1}\);

\( C_{\text{gwf}} \): Compression coefficient of natural gas under bottom hole flow pressure, MPa\(^{-1}\).

\( \bar{P}_{\text{pss}} \): Average formation pressure at the initial stage of pseudo steady state, MPa;

\( P_{\text{wf-pss}} \): Bottom hole flow pressure at the initial stage of pseudo steady state, MPa;

\( P_i \): Original formation pressure, MPa;

\( u_g \): Viscosity of natural gas, mPa·s;

\( C_g \): Compression coefficient of natural gas, MPa\(^{-1}\);

\( \lambda : \frac{(\bar{u}_g\bar{C}_g)}{(u_{\text{gwf}}C_{\text{gwf}})} \).

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Author contributions
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The authors declare no competing interests.

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