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Reasonable production allocation model of gas wells for deep tight gas reservoirs with the edge water

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Deep tight gas reservoirs are one of the important unconventional gas reservoirs. Deep burial, tight reservoirs have many characteristics, including diverse accumulation patterns, multiple accumulation regulations, low natural energy generation, complex gas–water relationship, and intricate seepage mechanism. These features of gas reservoirs put forward the requirement for new methods for a reasonable production allocation of horizontal wells and optimization of such allocations from the perspective of stress sensitivity. While CO_2 huff-and-puff-based models, numerical simulation models, and thermos-hydrodynamic models have been built to solve these issues, there is still a lack of theoretical guidance for reasonable production allocation, especially with the edge-water problem. Here, we present a new one-dimensional mathematical and physical model to capture the stable movement of the gas–water interface in deep tight edge-water gas reservoirs. Our results show that there is a starting pressure in deep tight gas reservoirs. The starting pressure gradient increases with the growth of water saturation, which is far greater than the starting pressure gradient of medium, shallow gas reservoirs under the same water saturation. In addition, by considering the stable movement of the gas–water interface under the starting pressure, we found that the gas well has a larger upper limit of production differential pressure, a smaller seepage velocity, and a lower upper limit of production allocation. Finally, we make a comparison between our model results and production characteristics of real gas wells and find a consistency between the model results with real data. Our model provides a theoretical framework for reasonable production allocation of gas wells in deep tight gas reservoirs with the edge water.

KEYWORDS

tight gas reservoirs, edge-water gas reservoir, reasonable production allocation, starting pressure, production differential pressure

Abbreviations: v_g, gas seepage velocity, m/s; k_g, vapor phase permeability under bound water, 10^{-3}um^2; u_g, gas viscosity, mPa●s; p_g, formation pressure in the gas phase, MPa; x, one-dimensional fluid model distance, m; λ, starting pressure gradient, MPa/m; ρ_g, gas density, g/cm^3; g, acceleration due to gravity, 9.8 m^2/s; α, formation inclination, rad; v_w, formation water seepage velocity, m/s; k_w, formation water permeability under residual gas saturation conditions, 10^{-3}um^2; u_w, formation water viscosity, mPa●s; p_w, formation pressure in the aqueous zone, MPa; q_{sc}, natural gas surface production, m^3/s; $\bar{p}$, conversion pressure, MPa; p_e, gas–water boundary formation pressure, MPa; p_{wf}, bottom flow pressure, MPa; L, one-dimensional distance from the gas–water interface, m; A, seepage cross-sectional area, m^2; B_g, natural gas volume factor, dimensionless.

1 Introduction

Reasonable production allocation is critical for the policy and project design of gas reservoir development (Li et al., 2006) and plays an important role in maintaining stable production of gas reservoirs and extending the product life cycle of gas wells. It is important to increase gas reservoir recovery (Selemenev et al., 2008; Li et al., 2021) and achieve efficient gas reservoir development (Khan et al., 2014; Sergeychev et al., 2020), which has been a focus of recent research (Li et al., 2018; Li et al., 2020). For conventional gas reservoirs, the frequently used methods for reasonable production allocation of gas wells include empirical method, nodal systems analysis, gas recovery curve method, profit analysis of production, reasonable drawdown pressure, and critical liquid-carrying flow rate (Liu et al., 1999; Li et al., 2008; Liu et al., 2013; Chen et al., 2016; Liu et al., 2022). Among these methods, empirical method, nodal systems analysis, gas recovery curve method, and profit analysis of production are commonly used in guiding production allocation based on pressure-depletion drive, while the remaining two are basically used to make reasonable regulations for gas wells of the water-producing and water-drive gas reservoirs. Often, a combination of these methods is applied to guide the efficient development of conventional gas reservoirs.

However, with the exploitation of gas reservoirs, conventional gas reservoirs are gradually exhausted, and unconventional gas reservoirs become increasingly important as a replacement resource. Deep tight gas reservoirs, as an important type of unconventional gas reservoirs, have the characteristics of deep burial, tight reservoirs, diverse accumulation patterns, multiple accumulation regulations, low natural energy generation, complex gas–water relationship, and intricate seepage mechanism (Buijs et al., 2020). These special gas reservoir characteristics put forward new requirements for reasonable production allocation. There are many recent studies focused on tight gas reservoirs, such as 3D modeling (Gonzalez et al., 2014), an integrated approach with detailed static and dynamic reservoir modeling (Weijermans et al., 2016), and cross-plot multiple regression analysis (Gai et al., 2015).

Considering gas reservoirs with the edge-water issue, there are several approaches designed to enhance oil recovery, optimize CO_2 huff-n-puff by multiple horizon wells, and solve complex reservoir issues. Hao et al. (2017) utilized CO_2 huff-and-puff to reduce CO_2 emissions and enhance oil recovery in an edge-water flock-block reservoir. Hong (1990) proposed a numerical simulation model to elucidate recovery mechanisms and find optimum operating strategies for a steeply dipping, heavy oil reservoir. Evgenii et al. (2015) discussed the results of thermos-hydrodynamic modeling performed on the sector models and selected the most effective option for the further development of the edge area of the reservoir. Wang et al. (2019) devised a physical and numerical conceptional model of a fault-block reservoir to improve CO_2 sweeping efficiency by multiple horizontal wells. Anthony et al. (2015) developed a single-well numerical simulation model to detect aquifer water encroachment into an oil reservoir.

Referring to starting pressure problems, Wang et al. (2017) introduced a factor called starting pressure gradient (SPG) and proposed three methods to characterize the SPG in tight sandstone oil reservoir numerical simulation. Liu et al. (2011) carried out laboratory tests to study the gas slippage and quasi starting pressure in water-bearing gas reservoirs of low permeability and found that the relationship between the quasi SPG and the ratio of core coefficient and water saturation was a power function. Yang et al. (2016) considered the influence of stress sensitivity on the working system of the gas well and used numerical simulation to analyze the impact of stress sensitivity on the ultimate recovery of the gas well under different production distribution conditions.

Lv et al. (2017) established a new reasonable production allocation method for horizontal wells with different production capacities and different single-well control reserves through statistical analysis. Lin et al. (2022) conducted a detailed gas reservoir analysis in the Anyue gas field of the Sichuan Basin and determined the diversities of pressure system, gas–water interface, bitumen content, and charging time.

Based on their results, they provided suggestions for the optimization of gas well production allocation. However, there is still a lack of theoretical framework for the reasonable production allocation of gas wells for deep tight gas reservoirs with the edge-water problem. This might lead to potential issues, such as premature flooding of most gas wells and restriction of the high-quality development and resource utilization of deep tight gas reservoirs. Therefore, we present a new simplified model through the fluid seepage theory to provide a theoretical basis for optimizing the working system of deep tight gas reservoirs. Compared with the previous studies, we consider the influence of the starting pressure gradient on the fluid flow, which provides a theoretical basis for reasonable production allocation of complex hydrocarbon reservoirs.

2 Differential equations of natural gas motion in deep tight gas reservoirs with the edge water

A large number of studies have found that compared with conventional gas reservoirs, tight gas reservoirs commonly have a starting pressure due to the characteristics of reservoir densification and low abundance (Lv et al., 2002; Wang et al., 2013; Zhan et al., 2022; Zholobov et al., 2022). Taking a deep tight gas reservoir in western Sichuan as an example, core analysis experiments show that the starting pressure gradient increases with the growth of water saturation. When the water saturation rises from 40% to 60%, the starting pressure gradient rises from 0.0277 MPa/m to 0.0339 MPa/m, which is about five times that of a medium, shallow gas reservoir under the same water saturation condition (Figures 1, 2). This is because the deep tight gas reservoir is buried deeper, resulting in a stronger compaction and larger starting pressure gradient than medium, shallow gas reservoirs. It can be seen that the starting pressure gradient of underground seepage initiation of natural gas in deep tight gas reservoirs cannot be ignored. Thus, without considering other forces, the differential equation of the underground seepage motion of natural gas is

$$v_g = -\frac{k_g}{u_g}\left(\frac{\partial p_g}{\partial x} + \lambda + \rho_g g \sin\alpha\right). \tag{1}$$

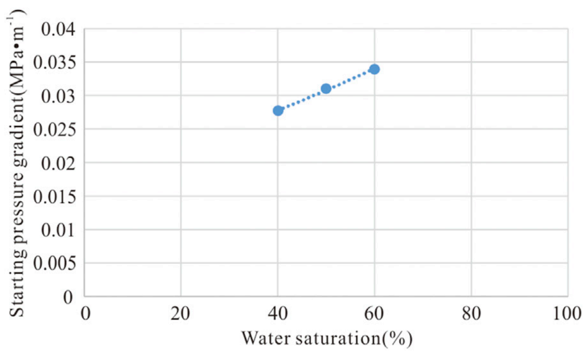

FIGURE 1
Starting pressure of typical deep tight gas reservoirs in western Sichuan under different water saturation conditions.

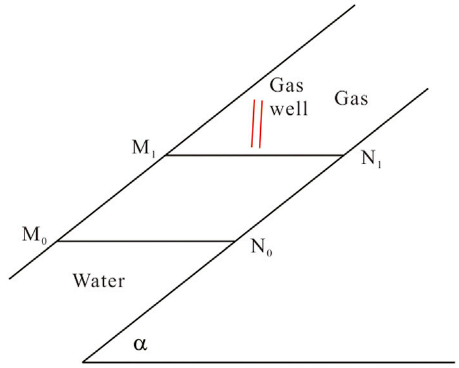

FIGURE 3
Simplified geological model of an edge-water gas reservoir.

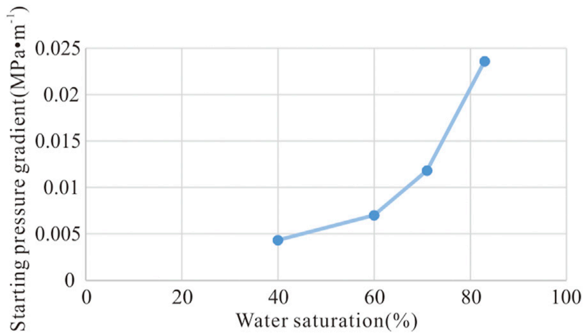

FIGURE 2
Starting pressure of typical medium, shallow gas reservoirs in western Sichuan under different water saturation conditions (Zhan et al., 2022).

3 Establishment of a reasonable production allocation model of gas wells for deep tight gas reservoirs with the edge water

We assume that the dip of a gas reservoir with the edge water is α, the gas reservoir is an isotropic homogeneous reservoir, and the initial gas–water interface is a horizontal plane (M_0N_0). The gas well is arranged in a relatively high part above the gas–water interface, and the gas–moisture interface moves to the bottom of the well after the gas well is put into production. At this time, the gas–moisture interface faces difficulty in maintaining the original horizontal state, becoming a curved surface (M_1N_1), forming a complex spatial movement and resulting in the non-uniform advancement of the edge water inside the gas reservoir (Wang et al., 2013; Temizel et al., 2015) (Figure 3). Taking the gas–water interface M_1N_1 as the research object, according to the fluid seepage theory, by considering the influence of starting pressure and gravity and ignoring the capillary pressure, the seepage of natural gas is satisfied as

$$v_g = -\frac{k_g}{u_g}\left(\frac{\partial p_g}{\partial x} + \lambda + \rho_g g \sin\alpha\right). \tag{2}$$

Formation water seepage is satisfied as

$$v_w = -\frac{k_w}{u_w}\left(\frac{\partial p_w}{\partial x} + \rho_w g \sin\alpha\right). \tag{3}$$

Since the pressure gradient is equal at the gas–moisture interface, that is,

$$\left.\frac{\partial p_g}{\partial x}\right|_{M_1N_1} = \left.\frac{\partial p_w}{\partial x}\right|_{M_1N_1}, \tag{4}$$

using Eqs 2, 3, 4, we have

$$v_w = \frac{k_w}{u_w}\frac{u_g}{k_g}v_g - \frac{k_w}{u_w}\left(\left(\rho_w - \rho_g\right)g\sin\alpha - \lambda\right). \tag{5}$$

In addition, the difference in seepage velocity of the two-phase fluid on the gas–moisture interface M_1N_1 is

$$\triangle v = v_w - v_g = \left(\frac{k_w}{u_w}\frac{u_g}{k_g} - 1\right)v_g - \frac{k_w}{u_w}\left(\left(\rho_w - \rho_g\right)g\sin\alpha - \lambda\right). \tag{6}$$

According to the previous research results (Li et al., 2008; Li et al., 2001; Liu et al., 1998), only when $v_w \le v_g$, the gas–water interface can maintain stable motion to ensure stable production of gas wells, that is, $\triangle v \le 0$, according to Eq. (6), thus

$$v_g \le \left|\frac{\frac{k_w}{u_w}\left(\left(\rho_w - \rho_g\right)g\sin\alpha - \lambda\right)}{1 - \left(\frac{k_w}{u_w}\right)\left(\frac{u_g}{k_g}\right)}\right|. \tag{7}$$

Equation 7 is the condition that should be met for the stable promotion of natural gas seepage velocity at the gas–water interface of deep tight gas reservoirs with the edge water. We set that the seepage cross-sectional area of the gas well is A, the distance between the gas well and the gas–water interface is L, the pressure at the gas–water boundary is p_e, and the flow pressure at the bottom of the well is p_{wf}. According to Eq. (2), the gas phase stabilizes the seepage velocity, that is,

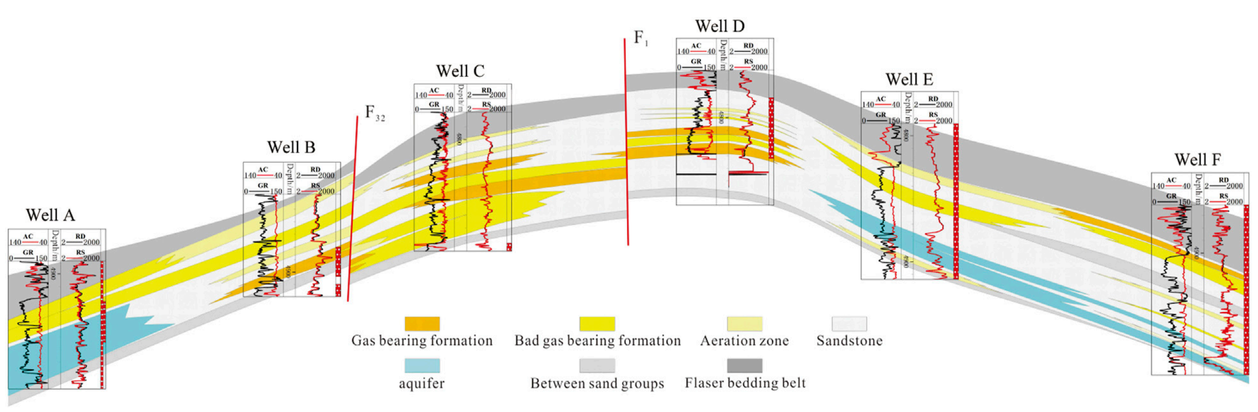

FIGURE 4
Gas reservoir profile of a deep tight gas reservoir in western Sichuan.

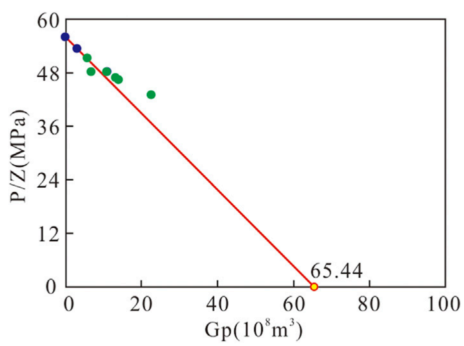

FIGURE 5
Material balance diagnosis diagram of a deep tight gas reservoir in western Sichuan.

$$v_g = \frac{q_{sc}B_g}{A} = -\frac{k_g}{u_g}\left(\frac{\partial \bar{p}}{\partial x}\right), \tag{8}$$

and

$$\bar{p} = p + \lambda x + \rho_g g x \sin\alpha. \tag{9}$$

Equations 8, 9 are integrated by the separated variable method:

$$q_{sc} = \frac{k_g A}{u_g B_g}\left(p_e - p_{wf} - \lambda L - \rho_g g L \sin\alpha\right). \tag{10}$$

Using Eqs 8, 10, we obtain stable seepage velocity in the gas phase:

$$v_g = \frac{k_g}{u_g}\left(p_e - p_{wf} - \lambda L - \rho_g g L \sin\alpha\right). \tag{11}$$

Using Eqs 7, 11, the production pressure difference in stable motion at the gas–water interface is obtained as

$$\Delta p = p_e - p_{wf} \le \left|\frac{\left(\left(\rho_w - \rho_g\right) g \sin\alpha - \lambda\right)}{1 - \frac{k_g}{u_g}\frac{u_w}{k_w}}\right| + \lambda L + \rho_g g L \sin\alpha. \tag{12}$$

Using Eqs 10, 12, we have the reasonable yield of stable motion at the gas–water interface as

$$q_{sc} \le \left|\frac{k_g A\left(\left(\rho_w - \rho_g\right) g \sin\alpha - \lambda\right)}{u_g B_g\left(1 - \frac{k_g}{u_g}\frac{u_w}{k_w}\right)}\right|. \tag{13}$$

When there is no starting pressure, that is, $\lambda = 0$, substituting Eqs 11, 12, 13, we obtain

$$v_g = \frac{k_g}{u_g}\left(p_e - p_{wf} - \rho_g g L \sin\alpha\right), \tag{14}$$

$$\Delta p = p_e - p_{wf} \le \left|\frac{\left(\rho_w - \rho_g\right) g \sin\alpha}{1 - \frac{k_g}{u_g}\frac{u_w}{k_w}}\right| + \rho_g g L \sin\alpha, \tag{15}$$

and

$$q_{sc} \le \left|\frac{k_g A\left(\rho_w - \rho_g\right) g \sin\alpha}{u_g B_g\left(1 - \frac{k_g}{u_g}\frac{u_w}{k_w}\right)}\right|. \tag{16}$$

According to Eqs 14–16, that is, when there is no starting pressure, the seepage velocity, reasonable pressure difference, and reasonable yield of the boundary of the side water reservoir meet the critical conditions of conventional side water and gas reservoir proposed by Li et al. (2008). Due to the existence of starting pressure, a larger production pressure difference and smaller gas well production are required to make the gas–water interface evenly promoted to achieve stable and normal production of gas wells due to the existence of starting pressure. This provides a theoretical basis for a reasonable production allocation of deep dense edge-water and gas reservoirs.

4 Model application

Next, we apply our theoretical model to a real deep tight gas reservoir in western Sichuan as an example. This is a typical deep tight gas reservoir, with an average buried depth of 4,500 m, average porosity of 4%, and average permeability of pressure

TABLE 1 Statistical comparison of different models.

Type	Production differential pressure upper limit (MPa)	Reasonable upper yield limit (10^4 m^3 d^{-1})
Considering starting pressure	54.95	21
Without considering starting pressure	35.73	35

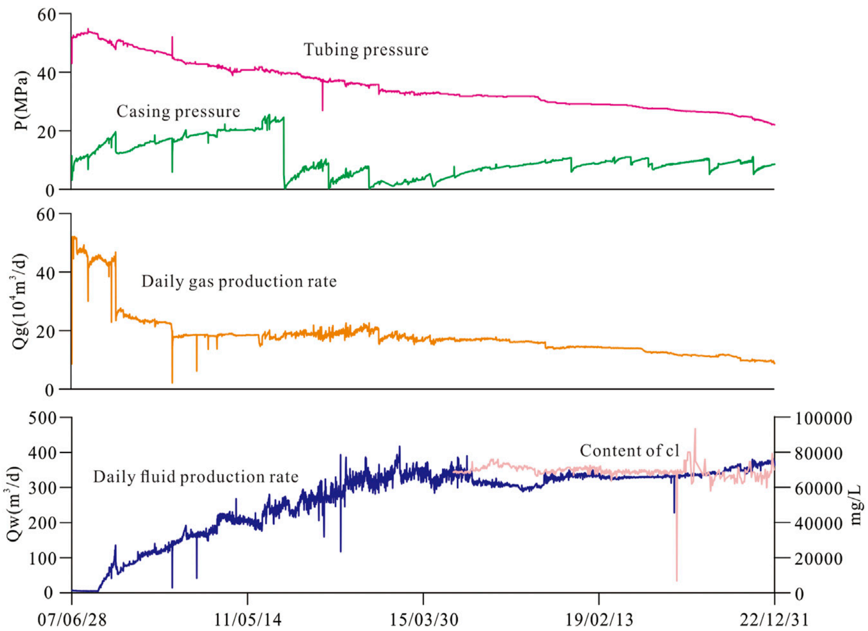

FIGURE 6
Production curve of typical wells in a deep tight gas reservoir in western Sichuan.

recovery interpretation of 0.49 md. The comprehensive logging, testing, and dynamic monitoring study shows that this reservoir is a water and gas reservoir on one side (Figures 4, 5). Using the comprehensive research results from geology and gas reservoir engineering, we use equations (12), (13), (15), and (16), respectively, to calculate the reasonable pressure difference and the upper limit of reasonable production of the gas well while considering with or without a starting pressure, as in Table 1.

From the production curve of the gas well, we can see that the well was put into production in 2007 and mined by using the fixed production and pressure reduction method. The initial production was more than 40×10^4 m^3 d^{-1}, which was much greater than the upper limit of the stable movement of the gas–water boundary (21×10^4 m^3 d^{-1} or 35×10^4 m^3 d^{-1}), resulting in a waterless production period of only about 1 year for the gas well. The water production rose rapidly afterward, with a rapid advancement of edge water under high-production conditions. In June 2008, the work system was adjusted to about 25×10^4 m^3, and the rise rate of gas well water production slowed down. The work system was further adjusted to about 20×10^4 m^3 d^{-1}, and the gas well production was stable. The overall performance was characterized by double stability of gas production and water production, which was close to the upper limit of the stable movement of the gas–water boundary under the condition of starting pressure. All these results indicate that our model has good reliability and applicability (Figure 6).

5 Conclusion

Core experimental analysis shows that there is a starting pressure in the deep tight gas reservoir, and the starting pressure increases rapidly when the water saturation rises. The starting pressure gradient of the deep tight gas reservoir is five times that of the medium, shallow tight gas reservoir. We built a new theoretical framework to capture all these dynamics in the deep tight gas reservoir. More specifically, we established an upper limit quantitative model to consider the seepage velocity with water stable movement, production pressure, and reasonable production of the deep tight gas reservoir with the edge water of the gas–water interface. Compared with the previous research results, the existence of the starting pressure leads to a lower seepage rate and lower production upper limit in the gas well but expands the upper limit of the production pressure difference. We further applied our model to a real example of a deep tight gas reservoir. The reasonable upper limit calculated using our theoretical work is consistent with the actual production characteristics of the gas well. This demonstrates the reliability and applicability of our model, which can function as a theoretical basis for the formulation of the stable production and reasonable output of deep tight gas reservoir wells with edge water.

Data availability statement

The original contributions presented in the study are included in the article/Supplementary Material; further inquiries can be directed to the corresponding author.

Author contributions

WH contributed to conceptualization, methodology, analysis, and writing; NN and YS contributed to the experiment design; YX contributed to data collection; ZZ contributed to investigation, supervision, and writing—review and editing. All authors have read and agreed to the published version of the manuscript.

Conflict of interest

ZZ and NN were employed by Southwest Oil and Gas Company, SINOPEC. YS was employed by PipeChina Oil and Gas Control Center.

The remaining authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

The reviewer WY declared a shared affiliation with the author YS to the handling editor at the time of review.

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