An Unsteady-State Productivity Model and Main Influences on Low-Permeability Water-Bearing Gas Reservoirs at Ultrahigh Temperature/High Pressure

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ABSTRACT: Currently, there is insufficient knowledge on the development of China’s low-permeability gas reservoirs under ultrahigh-temperature and high-pressure conditions; furthermore, the actual development process is difficult and has high technical demands. For example, the Ledong block in the South China Sea is a typical gas reservoir characterized using ultrahigh temperature (190 °C), high pressure (90 MPa), high water production, and low permeability (less than 1 mD). However, it is difficult to determine the factors influencing its production capacity, and the application of the traditional production capacity model is problematic because of the production of water. Accordingly, this study, which is based on the seepage theory, considers the influence of water production on the productivity of a single well; this study establishes an evaluation method for a low-permeability water-bearing gas reservoir vertical well (i.e., a highly deviated well) to determine how an unsteady state affects productivity. This method comprehensively considers stress sensitivity, initial pressure gradient, gas−water permeability, formation thickness, absolute permeability, supply radius, discharge radius, and well deviation angles to clarify the main factors affecting the productivity of single wells. Statistical methods are used to calculate and analyze the key influential factors, and this study provides quantitative evaluation methods to understand the productivity (and its influencing factors) of both vertical and highly deviated wells and the law of productivity decline. The model calculates the unblocked flow rate for 18 years as $319 \times 10^4$ m$^3$/d. Compared with the actual production unblocked flow rate of $332 \times 10^4$ m$^3$/d, the average error is 3.9%, which is within the allowed engineering range. Research shows the following order of factor influence on productivity: produced water−gas volume ratio > permeability > stress sensitivity coefficient > reservoir thickness > start-up pressure gradient > well deviation angle > discharge radius. Water saturation is the main factor affecting the unsteady-state productivity of gas wells in low-permeability gas reservoirs. In this study, with a production time of 100 days, the water saturation increases from 45 to 85%, and the open flow of the gas well decreases significantly from $30.1 \times 10^4$ to $1.6 \times 10^4$ m$^3$/d, which is a decrease of 94.7%. Moreover, a continuous increase in the stress sensitivity coefficient, start-up pressure gradient, and water saturation caused a leftward shift in the inflow performance relationship curves of the modeled gas wells, whereas their production decreased.

1. INTRODUCTION

The Ledong block is in the Yinggehai Basin, one of the world’s three largest high-temperature and high-pressure basins,1 as shown in Figure 1. It exhibits the “double-high and double-low” characteristics, including high pressure, high temperature, low porosity, and low permeability, making it representative in offshore ultrahigh-temperature and high-pressure gas fields. The offshore Le 10 ultrahigh-temperature (190 °C), high-pressure (90 MPa), and low-permeability (<1 mD) gas reservoir has ultrahigh temperature and high pressure, low porosity, and ultralow reservoirs. Owing to a lack of experience in similar gas reservoir mining, investigating the single-well productivity of a gas reservoir is critical in improving the recovered oil and gas yields in the gas-field dynamic prediction and gas production planning. Many domestic and foreign studies have been conducted on the productivity analysis methods of ultrahigh-temperature and high-pressure gas reservoirs,1−8 and some related nonsteady-state capacity analysis models have also been established.9−26

In 1936, Deussen20 proposed the use of the volumetric method as a key to determine the drainage area controlled by a
established a new model for determining the productivity of highly inclined gas wells in anisotropic reservoirs. However, the model ignored the effects of stress sensitivity and starting pressure gradient, not considering the gas–water two-phase seepage.

In subsequent studies, scholars gradually realized the impact of stress sensitivity on productivity. Later, in 2010, Kuznetsov et al. established a new semianalytical model of horizontal well productivity. Their model assumes reservoir homogeneity, and the flow conforms to Darcy’s law. It establishes differential equations, and the fracture grid is treated with infinite conductivity. In their 2011 study, Wen et al. considered the influence of reservoir stress sensitivity based on the gas–water two-phase seepage law and established the binomial productivity equation for water-producing gas wells in stress-sensitive gas reservoirs using the generalized Darcy formula. Then, in 2014, Wen et al. targeted the productivity characteristics of abnormally high-pressure gas reservoirs in the Yinggehai Basin, a new binomial gas well productivity equation considering the stress sensitivity. In 2015, Ghahri et al. established a new model for determining the productivity of horizontal wells in low-permeability sandstone gas reservoirs, considering the gas reservoir thickness. The following year, Zhou et al. determined the productivity equation of the pseudopressure method for gas wells, according to the stress sensitivity of the reservoir. The study by Zhang et al. established a productivity model considering reservoir stress sensitivity and gas–water two-phase seepage capacity changes. However, the model ignored the effects of gravity and capillary force. In these studies, the impact of the starting pressure gradient and permeability on productivity was not considered.

With the advancements in the research, scholars have gradually realized that diverse factors affect the productivity. In 2018, Lu et al. established the pseudosingle-phase stable point productivity evaluation method and the gas–oil two-phase stable productivity evaluation method. In their 2019 study, Liu et al. focused on the simultaneous appearance of gas and water in gas reservoirs. They considered the influence of gas–water two-phase seepage flows on productivity under irreducible water production conditions and established a productivity equation for high-temperature and high-pressure gas reservoirs. This equation considers the effects of nonsteady-state pressure correction and stress sensitivity but ignores the effect of initial pressure gradients on productivity.

In recent years, the productivity models established by scholars have increasingly considered the influence of multiple factors. Jiang et al. established a composite elliptical flow model for fractured wells to analyze the productivity changes in triple-medium gas reservoirs considering SRV. In 2020, Kadeethum et al. analyzed the influence of initial reservoir pressure, fracture orientation, fracture stiffness, and well pressure on oil well productivity. In 2021, Li et al. comprehensively considered the effects of non-Darcy and stress-sensitive factors and established a new dual-medium radial compound binomial productivity model. However, the model does not consider the impact of other influential factors, such as the well inclination angle on productivity. Chen and Jinjie proposed suitable productivity evaluation methods for fractured vertical well CBM reservoirs and conducted sensitivity analyses of different parameters affecting the productivity. The water storage coefficient, conductivity coefficient, and permeability mainly affect the production capacity at an early stage. Wang et al. established a single-well productivity equation for fractured-vuggy reservoirs based on a triple-medium model and analyzed the main seismic attributes affecting the single-well productivity, including the distance, RMS, frequency attenuation percentage, bed area, frequency attenuation coefficient, and sweet spot minimum and maximum. In 2022, Zhong et al. studied the seepage capacity of formation fluids in the fracture network and found that the interlayer contradiction between injection and production wells and low methane flow capacity resulted in poor production capacity and insensitivity to production parameters. Bao et al. studied the storage and flow behaviors of CO2 in shale under high-temperature and high-pressure reservoir conditions via dual-porosity and dual-permeability models and evaluated the CO2 storage potential and injection capacity of Lower Bakken Shale. They found that adsorption accounts for most of the CO2 injection potential in shale reservoirs, and the fracture network reformation plays a vital role in accelerating CO2 injection. However, the study aimed at shale reservoirs with a modified fracture network. However, such studies are mostly limited to fractured wells or shale gas reservoirs after reservoir reconstruction, and the factors affecting the productivity are not highly correlated with unconventional gas reservoirs. Therefore, studying the unsteady-state productivity model of ultrahigh temperature, high-pressure, and low-permeability gas reservoirs containing CO2 and analyzing the factors affecting the productivity remain necessary.

In summary, both domestic and international researchers have studied many unsteady-state productivity models. However, with the discovery of more ultrahigh-temperature, high-pressure, low-permeability gas reservoirs in China, the existing research is inadequate, and the following problems exist. First, it is difficult to adapt the existing productivity models to the single-well productivity of low-permeability water-bearing gas reservoirs under ultrahigh-temperature and high-pressure conditions. Additionally, the existing models ignore the productivity impact of start-up pressure gradients, stress sensitivities, and low-velocity non-Darcy seepage flows. In single-well water production, there are numerous main controlling factors that affect productivity, and the degree of influence of these factors on productivity remains unclear.
Second, under ultrahigh-temperature and high-pressure conditions, the two-phase seepage capacity in gas reservoirs is strong, and the impact on the productivity of low-velocity non-Darcy seepage in low- and ultralow-permeability reservoirs is unclear. Consequently, it is not possible to make accurate production forecasts for ultrahigh-temperature, high-pressure, low-permeability gas reservoirs. Therefore, this study establishes an unsteady productivity model for gas wells in ultrahigh temperature, high-pressure, low-permeability water-bearing gas reservoirs. Therefore, this study considers the impact of water production on the unsteady productivity of a single well. Additionally, the model considers the effects of start-up pressure gradients, stress sensitivities, and gas–water two-phase seepage.

Compared with the traditional single-well unsteady-state productivity model, the new model established in this study is innovative for the following reasons: First, the model is more suited to the complex gas reservoir conditions found in the Ledong area of the South China Sea, and it produces more accurate productivity forecasts; additionally, it considers the effects of temperature and pressure conditions, stress sensitivities, start-up pressure gradients, water cut, reservoir thickness, absolute permeability, discharge radius, and well deviation angle on the unsteady productivity of ultrahigh-temperature, high-pressure, low-permeability gas reservoirs. Furthermore, it comprehensively considers the effects of low-velocity, non-Darcy gas–water two-phase seepage; it can predict the gas and water production of gas wells at the same time, and its consideration factors are comprehensive. This study provides quantitative evaluation methods for understanding the productivity of both vertical and highly deviated wells, the law of productivity decline, and the key factors affecting the productivity of vertical and highly deviated wells. The open flow rate in June 2018 was calculated to be $319 \times 10^4$ m$^3$/d based on the established nonsteady-state gas well productivity model. Compared with the measured unblocked flow rate of $332 \times 10^4$ m$^3$/d, the average error was 3.9%, which is within the engineering allowable range.

2. RESULTS AND DISCUSSION

2.1. Establishment of an Unsteady Productivity Model for Ultrahigh-Temperature and High-Pressure Water-Producing Gas Wells

2.1.1. Vertical Well Unsteady Productivity Model

2.1.1.1. Physical Model Description

(1) Gas reservoirs are homogeneous and of equal thickness with impermeable top and bottom boundaries.

(2) The gas reservoir contains gas–water two-phase fluids, the gas and water are immiscible, there is isothermal seepage flow, and Darcy’s law is followed.

(3) The effects of stress sensitivity and the start-up pressure gradient are considered.

(4) The compression of gas reservoir rocks and fluids is considered.

(5) The influence of the capillary pressure of the fluid on the seepage process is considered.

(6) Gas wells are produced under constant bottom-hole pressure.

2.1.1.2. Derivation of Unsteady-State Productivity Formula for Vertical Wells

The two-phase continuity equation of gas and water is:

$$\nabla \cdot (\rho \nu) = \frac{\partial}{\partial t} (\phi \rho \Sigma)$$  \hspace{1cm} (1)

$$\nabla \cdot (\rho_w \nu_w) = \frac{\partial}{\partial t} (\phi \rho_w S_w)$$  \hspace{1cm} (2)

where $\rho$ is the gas-phase density, g/cm$^3$; $\rho_w$ is the water-phase density, g/cm$^3$; $\nu$ is the gas flow velocity, cm/s; $\nu_w$ is the water-flow velocity, cm/s; $t$ is the time, s; $\phi$ is the porosity (decimal); $S_g$ is the gas saturation (decimal); and $S_w$ is the water saturation (decimal).

The gas-phase motion equation below considers the start-up pressure gradient and stress sensitivity:

$$v_g = 0, \quad |\nabla p| < \lambda_g$$

$$v_g = -\frac{K_g e^{-\alpha (p_g - p)}}{\mu_g} (\nabla p_g - \lambda_g), \quad |\nabla p| \geq \lambda_g$$  \hspace{1cm} (3)

The water-phase motion equation also considers the start-up pressure gradient and stress sensitivity:

$$v_w = 0, \quad |\nabla p_w| < \lambda_w$$

$$v_w = -\frac{K_w e^{-\alpha (p_w - p)}}{\mu_w} (\nabla p_w - \lambda_w), \quad |\nabla p| \geq \lambda_w$$  \hspace{1cm} (4)

where $p$ is the gas pressure, atm; $p_w$ is the water-phase pressure, atm; $p_o$ is the initial pressure, atm; $\lambda_g$ is the gas-phase start-up pressure gradient; $\lambda_w$ is the water-phase start-up pressure gradient, atm/cm; $\mu_g$ is the viscosity in the gas phase, cP; $\mu_w$ is the viscosity in the water phase, cP; $K_g$ is the initial permeability, D; $\alpha$ is the stress sensitivity factor, atm$^{-1}$; $K_w$ is the relative permeability in the gas phase; and $K_{nw}$ is the relative permeability in the water phase.

Eqs 3 and 4 can be substituted into eqs 1 and 2 to obtain the mass conservation equations of the gas and water phases, as follows:

$$\nabla \cdot \left( \rho_g e^{-\alpha (p_g - p)} K_g (\nabla p_g - \lambda_g) \right) = \frac{\partial}{\partial t} (\phi \rho \Sigma)$$  \hspace{1cm} (5)

$$\nabla \cdot \left( \rho_w e^{-\alpha (p_w - p)} K_w (\nabla p_w - \lambda_w) \right) = \frac{\partial}{\partial t} (\phi \rho_w S_w)$$  \hspace{1cm} (6)

Considering the influence of the source and sink terms, eqs 5 and 6 can be rewritten as:
\[ \nabla \left[ \rho \frac{v_g e^{-\alpha(q_g - p_g)} K_{gr}(\nabla p_g - \lambda_g)}{\mu_g} \right] + q_{gv} = \frac{\partial}{\partial t} (\phi \rho S_g) \quad \text{(7)} \]

\[ \nabla \left[ \rho u e^{-\alpha(q_u - p_u)} K_{ru}(\nabla p_u - \lambda_u) \right] + q_{uw} = \frac{\partial}{\partial t} (\phi \rho S_u) \quad \text{(8)} \]

The above model involves four unknowns, that is, \( p_g \), \( p_w \), \( S_g \), and \( S_u \). However, as there are only two equations (eqs 7 and 8), two auxiliary equations are required to solve the model:

\[ S_g + S_w = 1 \quad \text{(9)} \]

\[ p_w = p_g - p_{gw} \quad \text{(10)} \]

where \( p_{gw} \) is the air and water capillary pressure (atm).

The flow coefficient can be defined as follows:

\[ \eta_g = \frac{\rho_g e^{-\alpha(q_g - p_g)} K_{gr}}{\mu_g} \quad \text{(11)} \]

\[ \eta_w = \frac{\rho_u e^{-\alpha(q_u - p_u)} K_{ru}}{\mu_u} \quad \text{(12)} \]

Then, the transformed mass conservation equation can be obtained:

\[ \nabla \cdot \left[ \eta_g (\nabla p_g - \lambda_g) \right] + q_{gv} = \frac{\partial}{\partial t} (\phi \rho S_g) \quad \text{(13)} \]

\[ \nabla \cdot \left[ \eta_w (\nabla p_w - \lambda_w) \right] + q_{uw} = \frac{\partial}{\partial t} (\phi \rho S_w) \quad \text{(14)} \]

Combining the auxiliary equations (eqs 9 and 10), the initial conditions, and the boundary conditions, a complete vertical unsteady-state productivity model can be derived. The strong nonlinearity of the simulation means that it has no analytical solution. Using the finite-difference method to discretely discretize the above model, the following can be obtained:

\[ \frac{\partial}{\partial x} \left[ \eta_g \left( \frac{\partial p_g}{\partial x} - \lambda_g \right) \right] + \frac{\partial}{\partial y} \left[ \eta_g \left( \frac{\partial p_g}{\partial y} - \lambda_g \right) \right] + q_{gv} = \frac{\partial}{\partial t} (\phi \rho S_g) \quad \text{(15)} \]

Then, a finite-difference method can be performed on the left end of eq 15 in the x and y directions at points \((i,j,n+1)\), as follows:

For the x-direction difference:

\[ \frac{1}{\Delta x_i} \left[ \eta_{g(i+1/2)} \left( \frac{p_{g(i+1)} - p_{g(i)}}{\Delta x_{i+1/2}} - \lambda_g \right) \right] - \eta_{g(i-1/2)} = \frac{1}{\Delta t} \left[ \left( \phi \rho S_g \right)^{n+1} - \left( \phi \rho S_g \right)^n \right] \quad \text{(16)} \]

For the y-direction difference:

\[ \frac{1}{\Delta y_j} \left[ \eta_{g(j+1/2)} \left( \frac{p_{g(j+1)} - p_{g(j)}}{\Delta y_{j+1/2}} - \lambda_g \right) \right] - \eta_{g(j-1/2)} = \frac{1}{\Delta t} \left[ \left( \phi \rho S_g \right)^{n+1} - \left( \phi \rho S_g \right)^n \right] \quad \text{(17)} \]

Then, a finite difference can be performed on the right end of eq 15:

\[ \frac{1}{\Delta t} \left[ \left( \phi \rho S_g \right)^{n+1} - \left( \phi \rho S_g \right)^n \right] \quad \text{(18)} \]

The substitution of eqs 161718 into eq 15 provides:

\[ \frac{1}{\Delta x_i} \left[ \eta_{g(i+1/2)} \left( \frac{p_{g(i+1)} - p_{g(i)}}{\Delta x_{i+1/2}} - \lambda_g \right) \right] - \eta_{g(i-1/2)} = \frac{1}{\Delta t} \left[ \left( \phi \rho S_g \right)^{n+1} - \left( \phi \rho S_g \right)^n \right] \quad \text{(19)} \]

Both sides of eq 19 are multiplied by the grid volume: \( V_{i,j} = \Delta x_i \Delta y_j h \). Then, the conduction coefficient and the second-order difference quotient operator in the x and y directions of the two-dimensional space can be defined as follows:

The conduction coefficient definition:

\[ T_{xg(i+1/2)} = \frac{V_{i,j} \eta_{g(i+1/2)}}{\Delta x_i \Delta y_j + \frac{1}{\Delta x_i}} \eta_{g(i+1/2)} \quad \text{(20)} \]

\[ T_{yg(j+1/2)} = \frac{V_{i,j} \lambda_{g(j+1/2)}}{\Delta y_j \Delta x_{i+1/2} + \frac{1}{\Delta y_j}} \lambda_{g(j+1/2)} \quad \text{(21)} \]

The definition of the second-order difference quotient operator:

\[ \Delta x T_{xg} \Delta p_{g} = T_{xg(i+1/2)} \left( p_{g(i+1)} - p_{g(i)} \right) - T_{xg(i-1/2)} \left( p_{g(i)} - p_{g(i-1)} \right) \quad \text{(22)} \]

\[ \Delta y T_{yg} \Delta p_{g} = T_{yg(j+1/2)} \left( p_{g(j+1)} - p_{g(j)} \right) - T_{yg(j-1/2)} \left( p_{g(j)} - p_{g(j-1)} \right) \quad \text{(23)} \]

The start-up pressure gradient difference coefficient definition:

\[ \lambda_{g(i,j)} = \frac{1}{\Delta x_i} \left( \eta_{g(i-1/2)} - \eta_{g(i+1/2)} \right) \lambda_g + \frac{1}{\Delta y_j} \left( \eta_{g(i-1/2)} - \eta_{g(i+1/2)} \right) \lambda_g \quad \text{(24)} \]
\[ \Delta_T g \Delta p_g^{n+1} + \Delta_T g \Delta p_{gw}^{n+1} + \Delta g_j^{n+1} + q_{gw} V_j \]
\[ = \frac{V_{ij}}{\Delta t} \left[ (\phi p_g S_g)^{n+1} - (\phi p_g S_g)^n \right] \]  
(25) 
and further simplified to:
\[ \Delta T g \Delta p_g^{n+1} + \Delta g_j^{n+1} + q_{gw} V_j = \frac{V_{ij}}{\Delta t} \left[ (\phi p_g S_g)^{n+1} - (\phi p_g S_g)^n \right] \]  
(26)

In the same way, the water-phase difference equation can be derived:
\[ \Delta T w \Delta p_w^{n+1} - \Delta T w \Delta p_{gw} + \Delta w_j^{n+1} + q_{ww} V_j \]
\[ = \frac{V_{ij}}{\Delta t} \left[ (\phi p_w S_w)^{n+1} - (\phi p_w S_w)^n \right] \]  
(27)

Among them, the equation \( p_w^{n+1} = p_w^n - p_{gw} \) is used to eliminate \( p_w^{n+1} \).
At this time, the pressure in eqs 26 and 27 only contains \( p_g^n \) and \( S_{gw} \).
To process the coefficients of the difference equation, the coefficients of the left-hand term in eqs 26 and 27 are displayed and processed in time:
\[ \begin{align*}
T_g &= T_g^n, T_w = T_w^n \\
p_g &= p_g^n, p_{gw} = p_{gw}^n, q_{gw} = q_{gw}^n, q_{ww} = q_{ww}^n
\end{align*} \]  
(28)

The treatment of the right term in eqs 26 and 27 is:
\[ \begin{align*}
p_g^{n+1} &= p_g^n + \delta p_g \\
S_{gw}^{n+1} &= S_{gw}^n + \delta S_{gw}
\end{align*} \]  
(29)

For the two phases of gas and water, the solution variable can be converted into solutions \( \delta p_g \) and \( \delta S_{gw} \) using eq 29.
Any point \((i, j)\) can be defined as point \( m \), and the compound function on the right side of eq 26 can be derived to obtain:
\[ \frac{V_{ij}}{\Delta t} \left[ (\phi p_g S_g)^{n+1} - (\phi p_g S_g)^n \right] \]
\[ = \frac{V_m}{\Delta t} \delta (\phi p_g S_m) \]
\[ = \frac{V_m}{\Delta t} (S_g p_g \delta \phi + \phi S_g \delta p_g + \phi p_g \delta S_g) \]  
(30)

\[ \delta \phi = \phi_0 c_\phi \delta p_g \]
\[ \delta p_g = \left( \frac{\partial \phi}{\partial p_g} \right) \delta \phi = \left( \frac{\partial \phi}{\partial p_g} \right)^n \delta p_g \]
\[ \delta S_g = -\delta S_{gw} \]  
(31)

where \( \phi_0 \) is the porosity at the reference pressure, and \( c_\phi \) is the rock compressibility at atm \(^{-1}\).

By substituting eq 31 into eq 30, all coefficients are displayed and processed, and the value of the \( n \) step takes \( m \) points:
\[ \frac{V_m}{\Delta t} \left[ S_g^n \phi_0^n c_\phi + \phi^n S_g \left( \frac{\partial \phi}{\partial p_g} \right) \delta p_g - \frac{V_m}{\Delta t} \phi_0^n \delta S_{gw} \right] \]
\[ = C_g \delta p_g + C_g \delta S_{gw} \]  
(32)

where
\[ \left\{ \begin{align*}
C_{gt1} &= V_m \left[ S_g^n c_\phi \phi + \phi^n S_g \left( \frac{\partial \phi}{\partial p_g} \right) \right] \\
C_{gt2} &= -\frac{V_m}{\Delta t} \phi_0^n
\end{align*} \]  
(33)

The capillary pressure is handled by an explicit method:
\[ \delta p_g = \delta(p_w + p_{gw}) = (p_w^{n+1} + p_{gw}^n) - (p_w^n + p_{gw}^n) = \delta p_w \]
\[ \delta p_{gw} = \delta(p_g^n + p_{gw}) = (p_g^n + p_{gw}^n) - (p_g^n + p_{gw}^n) = 0 \]  
(34)

According to the same procedure of the gas-phase equation, the right end of the water phase can be obtained as follows:
\[ \frac{V_m}{\Delta t} \left[ (\phi p_w S_w)^{n+1} - (\phi p_w S_w)^n \right] = C_w \delta p_g + C_w \delta S_{gw} \]  
(35)

where
\[ \left\{ \begin{align*}
C_{w1} &= V_m \left[ S_g^n c_\phi \phi + \phi^n S_g \left( \frac{\partial \phi}{\partial p_g} \right) \right] \\
C_{w2} &= -\frac{V_m}{\Delta t} \phi_0^n
\end{align*} \]  
(36)

By substituting eqs 28, 32, and 36 into eqs 26 and 27, the following is obtained:
\[ \Delta T g \Delta p_g^n + \Delta T g \Delta p_{gw} + \lambda_{gw} + q_{gw} V_m \]
\[ = C_g \delta p_g + C_g \delta S_{gw} \]
\[ \Delta T w \Delta p_w^n + \Delta T w \Delta p_{gw} - \Delta T w \Delta p_{gw} + \lambda_{ww} + q_{ww} V_m \]
\[ = C_w \delta p_g + C_w \delta S_{gw} \]  
(37)

After shifting the items:
\[ \Delta T g \Delta p_{gw} - C_g \delta p_{gw} - C_g \delta S_{gw} = R_g \]
\[ \Delta T w \Delta p_{gw} - C_w \delta p_{gw} - C_w \delta S_{gw} = R_w \]  
(38)

where
\[ \left\{ \begin{align*}
R_g &= -\Delta T g \Delta p_g^n - \lambda_{gw} - q_{gw} V_m \\
R_w &= -\Delta T w \Delta p_w^n - \lambda_{ww} - q_{ww} V_m
\end{align*} \]  
(39)

According to the idea of implicit pressure and explicit saturation, the two equations in eq 38 can be eliminated and solved, while \( \delta S_{gw} \) can be eliminated to obtain a linear pressure difference equation with only one variable \( \delta p_{gw} \):
\[ S_g \delta p_{gw} + W_{ij} \delta p_{gw} + C_g \delta p_{gw} + E_{ij} \delta p_{gw} + N_{ij} \delta p_{gw} = Q_{ij} \]  
(40)

For a five-diagonal coefficient matrix linear algebraic equation system formed by eq 40, the solution is \( \delta p_{gw} \). The obtained \( \delta p_{gw} \) is substituted into eq 38 to obtain \( \delta S_{gw} \), then, \( \delta p_{gw} \) and \( \delta S_{gw} \) are used to find \( p_g^n + S_{gw}^{n+1} \), and all other parameters at any point \( m \). All the new parameter values are substituted back to eq 38 (the difference equation) to obtain
the new time-step calculation formula. The above steps are repeated until the simulation time ends.

At the initial moment, the pressure and saturation of each point in the gas reservoir are constant, that is, the initial condition is as follows:

\[ p_g(x, y, t)|_{t=0} = p_i \]  
\[ S_w(x, y, t)|_{t=0} = S_{wi} \]

where \( p_i \) is the initial formation pressure (atm), and \( S_{wi} \) is the initial formation water saturation (decimal).

For gas wells with constant-pressure production, assuming that the bottom-hole pressure \( (p_{\text{wf}}) \) is known, then the gas and water production of the gas well is:

\[
Q_{\text{ok}} = \left( \frac{2\pi h K_0 e^{-\alpha_0 (p_i - p_f)} K_{rg}}{\mu_g B_g \ln(\theta_{eq,k} / \theta_w)} \right)^n_k \left( p_{\text{wf}}^{n+1} - p_{\text{wf}} - \lambda_g (\theta_{eq,k} - \theta_w) \right)_k \]

\[
Q_{\text{wk}} = \left( \frac{2\pi h K_0 e^{-\alpha_0 (p_i - p_f)} K_{rw}}{\mu_w B_w \ln(\theta_{eq,k} / \theta_w)} \right)^n_k \left( p_{\text{wf}}^{n+1} - p_{\text{wf}} - \lambda_w (\theta_{eq,k} - \theta_w) \right)_k \]

(43)

Here, \( \theta_{eq,k} = 0.14 \sqrt{\Delta x^2 + \Delta y^2} \), and the implicit pressure \( p_{\text{wf}}^{n+1} \) is used. If \( p_{\text{wf}}^{n+1} < p_{\text{wf}} \), the well should be closed, but if \( p_{\text{wf}}^{n+1} > p_{\text{wf}} \), then \( Q_{\text{ok}} \) and \( Q_{\text{wk}} \) should be calculated.

2.1.2. Unsteady-State Productivity Model for Highly Deviated Wells. 2.1.2.1. Physical Model Description.

Essentially, the physical unsteady-state productivity model for highly deviated wells is the same as that for vertical wells (Figure 2). The difference is that gas reservoirs develop with highly deviated wells rather than vertical wells. Therefore, the influence of the inclination angle on seepage is described by the pseudoskin coefficient, which results from the inclination of the borehole:

1. Gas reservoirs are homogeneous and of equal thickness with impermeable top and bottom boundaries.
2. The gas reservoir contains gas–water two-phase fluids; the gas and water are not mutually soluble, and the flow is isothermal, which obeys Darcy’s law.
3. The effects of stress sensitivity and start-up pressure gradient are considered.
4. The compression of gas reservoir rocks and fluids is considered.
5. The influence of the capillary pressure of the fluid on the seepage process is considered.
6. Gas wells are produced under constant bottom-hole pressure.

2.1.2.2. Derivation of an Unsteady Productivity Formula for Highly Deviated Wells. Based on the previously derived unsteady-state productivity model for vertical wells, considering that the pseudoskin coefficient due to borehole tilt is \( S_\theta \), the expression for the unsteady-state productivity of a highly deviated well can be derived as follows:

\[
\Delta T_g^n \Delta p_g^n + \Delta T_g^n \Delta \rho_g^n + \lambda_g^n + q_g^n V_m^n = C_g \delta_{g,wn} + C_{g,\delta_{g,wn}} \]

\[
\Delta T_w^n \Delta p_w^n + \Delta T_w^n \Delta \rho_w^n - \Delta T_w^n \Delta p_{eq,w}^n + \lambda_{wn}^n + q_{wn}^n V_m^n = C_w \delta_{w,wn} + C_{w,\delta_{w,wn}} \]

(45)

For a highly deviated well with constant-pressure production, assuming that the bottom-hole flow pressure \( (p_{\text{wf}}) \) is known, then the gas and water production rates of the highly deviated well, respectively, are as follows:

\[
Q_{\text{ok}} = \left( \frac{2\pi h K_0 e^{-\alpha_0 (p_i - p_f)} K_{rg}}{\mu_g B_g \ln(\theta_{eq,k} / \theta_w)} \right)^n_k \left( p_{\text{wf}}^{n+1} - p_{\text{wf}} - \lambda_g (\theta_{eq,k} - \theta_w) \right)_k \]

\[
Q_{\text{wk}} = \left( \frac{2\pi h K_0 e^{-\alpha_0 (p_i - p_f)} K_{rw}}{\mu_w B_w \ln(\theta_{eq,k} / \theta_w)} \right)^n_k \left( p_{\text{wf}}^{n+1} - p_{\text{wf}} - \lambda_w (\theta_{eq,k} - \theta_w) \right)_k \]

(46)

Among them, the expression of the quasi-skin coefficient \( (S_\theta) \) is:

\[
S_\theta = \left( 1 - \frac{\cos \theta}{\gamma} \right) \ln \left( \frac{4r_w}{L} \frac{1}{\beta^2} \right) + \cos \theta \ln \left( \frac{2\sqrt{\gamma} \cos \theta}{1 + \gamma} \right) \]

(48)

where \( \gamma = \sqrt{\cos^2 \theta + \frac{1}{\beta^2} \sin^2 \theta} \), \( L = \frac{h}{\cos \theta} \), \( \beta = \frac{K_h}{K_v} \)

(49)

where \( \theta \) is the well angle, \( \gamma \); \( L \) is the length of the highly deviated well section, \( m \); \( \beta \) is the anisotropy coefficient; and \( K_h, K_v \) is the permeability in the horizontal and vertical directions, \( mD \).

2.2. Quantitative Analysis of Factors Affecting Production Capacity. The basic parameters of Well No.13 in the Ledong block in the South China Sea are as follows: The original formation pressure of the gas reservoir where the well is located is 90.23 MPa, the temperature of the gas reservoir is 191 °C, the depth of the well is 4079.5 m, the thickness of the reservoir is 14.4 m, its porosity is 0.111, the logging permeability is 1.77 mD, and the water saturation is 0.43. Table 1 shows the composition of natural gas, while Figure 3 presents the gas–water phase permeability curve and capillary pressure curve, respectively. Other basic parameters are given in Table 2.
2.2.1. Influence of Temperature and Pressure on the Unsteady-State Productivity of Gas Wells.

The open flow rate of Well No. 13 decreases from 37.75 × 10^4 to 6.86 × 10^4 m^3/d, representing a decrease of 81.8%. It is clear that for the No. 13 well with its high water saturation and high water production, there are significant differences in the open flow dynamics calculated by high-temperature and high-pressure phase infiltration and normal-temperature and normal-pressure phase infiltration. This is because when the water saturation of a single well is high and the gas–water interfacial tension is low, which makes for an easy flowing water phase under conditions of ultrahigh temperature and high pressure. Therefore, the unblocked flow rate of a single well under ultrahigh-temperature and high-pressure conditions is lower than that under normal temperature and pressure.

2.2.2. Influence of the Stress Sensitivity Factor on the Unsteady-State Productivity of Gas Wells.

The stress sensitivity factor has a significant influence on the entire production process of a gas well. As shown in Figure 6, the open flow rate of the gas well decreases. Figures 7 and 8 show the influence of the stress sensitivity factor on the unsteady IPR curve and unsteady-state productivity of a gas well. With a 100-day production time and with the continuous increase in the stress sensitivity factor, the IPR curve of the gas well shifts to the left, and the gas well’s production decreases from 43.44 × 10^4 to 13.83 × 10^4 m^3/d, representing a decrease of 68.2%. As the bottom-hole flow pressure is reduced, the stress sensitivity leads to a more noticeable decrease in production, while an increase in the stress sensitivity factor causes the open flow rate of the gas well to decrease rapidly at first before slowing. When the

Table 1. Natural Gas Composition of Well No.13 in the Ledong Block of the South China Sea

| component | molar fraction (%) |
|-----------|--------------------|
| C1        | 68.13              |
| C2        | 1.76               |
| C3        | 0.37               |
| H2O       | 0.10               |
| N2        | 0.06               |
| CO2       | 0.05               |
| He        | 0.02               |
| C6        | 0.14               |
| N2O       | 5.88               |
| CO2       | 23.49              |
| He        | 0.00               |
| H2        | 0.00               |

Table 2. Basic Parameters of Gas Reservoirs and Wells

| parameter                              | value     |
|----------------------------------------|-----------|
| initial formation pressure (MPa)       | 90.8      |
| formation temperature (°C)             | 190       |
| discharge radius (m)                   | 500       |
| reservoir thickness (m)                | 39.8      |
| porosity                               | 0.1       |
| initial permeability (mD)              | 1.1       |
| initial water saturation               | 0.57      |
| start-up pressure gradient (MPa/m)     | 0.03      |
| stress sensitivity factor              | 1.0       |
| rock compressibility (MPa^−1)          | 0.03      |
| formation water volume factor          | 3.0       |
| formation water compressibility (MPa^−1)| 0.0001   |
| formation water viscosity (mPa.s)      | 0.01      |
| formation water density (g/cm^3)       | 1.006     |
| stratum anisotropy coefficient         | 3.16      |

Figure 3. Relative permeability curve of gas and water (left); air and water capillary pressure (right).

Figure 4. Open flow dynamics of Well No. 13 under different phase permeability curves.
production time is 100 days, the stress sensitivity factor increases from 0 to 0.1 MPa$^{-1}$, and the open flow rate of the gas well decreases from $43.4 \times 10^4$ to $6.6 \times 10^4$ m$^3$/d, representing a decrease of 84.8%.

2.2.3. Influence of the Start-Up Pressure Gradient on the Unsteady-State Productivity of Gas Wells. The start-up pressure gradient affects the entire production process of a gas well. As shown in Figure 9, with a 100-day production time and with the continuous increase in the start-up pressure gradient, the open flow of the gas well gradually decreases from $22.57 \times 10^4$ to $18.31 \times 10^4$ m$^3$/d, representing a decrease of 18.9%. Because of the existence of the start-up pressure gradient, only when the pressure gradient in the reservoir exceeds a certain value will the fluid in the reservoir flow. Therefore, the higher the start-up pressure gradient, the more difficult it is to supply reservoirs located far from the well, resulting in a decrease in gas well production. Figures 10 and 11 show the influence of the start-up pressure gradient on a well's unsteady IPR curve and unsteady productivity. With a 100-day production time, as the start-up pressure gradient increases from 0 to 0.1 MPa/m, the IPR curve of the gas well shifts to the left, and the open flow rate of the gas well decreases from $22.6 \times 10^4$ to $10.8 \times 10^4$ m$^3$/d, which is a decrease of 52.1%.
2.2.4. Influence of Water Saturation on the Unsteady-State Productivity of Gas Wells. Figure 12 depicts the effect of water saturation on the open flow performance of a gas well. With a 100-day production time and with the continuous increase in the water saturation, the open flow of the gas well gradually decreases from \(25.97 \times 10^4\) to \(17.67 \times 10^4\) m\(^3\)/d, which is a decrease of 32\%. The initial water saturation of the gas reservoir affects the entire production process of the gas well. As the water saturation increases, there is a decrease in the open flow of the gas well. The impacts of water saturation on the unsteady IPR curve and unsteady productivity of a gas well are presented in Figures 13 and 14. When the production time is 100 days, as the water saturation increases, the gas well IPR curve is seen to move leftward, and the gas well production decreases. As the water saturation increases, the open flow rate of the gas well decreases. With a production time of 100 days, the water saturation increases from 45 to 85\%, and the open flow of the gas well decreases significantly from \(30.1 \times 10^4\) to \(1.6 \times 10^4\) m\(^3\)/d, which is a decrease of 94.7\%. Therefore, water saturation is the main factor affecting the unsteady-state productivity of gas wells in low-permeability gas reservoirs.

2.2.5. Influence of the Reservoir Thickness on the Unsteady-State Productivity of Gas Wells. Figure 15 illustrates the influence of the reservoir thickness on the open flow performance of a gas well. The figure shows that as time increases, there is a gradual decrease in the open flow of the gas well. The well’s entire production process is affected by the thickness of the reservoir. As the thickness of the reservoir increases, the open flow rate of the gas well also increases. Figures 16 and 17 illustrate the influence of the reservoir thickness on the unsteady IPR curve and unsteady productivity, respectively, of a gas well. With a production time of 100 days, as the reservoir thickness increases, the IPR curve of the gas well shifts to the right, and the production of the gas well increases. As the thickness of the reservoir increases, there is an increase in the open flow of the gas well. With a 100-day production time, the thickness of the reservoir increases from 10 to 100 m, and the gas well’s open flow rate increases significantly from \(5.07 \times 10^4\) to \(50.7 \times 10^4\) m\(^3\)/d.
Therefore, the reservoir thickness is a key influential factor for the unsteady productivity of gas wells in low-permeability gas reservoirs.

2.2.6. Influence of Absolute Permeability on the Unsteady-State Productivity of Gas Wells. Figure 18 illustrates the influence of absolute permeability on the open flow performance of a gas well. The figure reveals that as time increases, the open flow of the gas well gradually decreases. Absolute permeability affects the entire production process of a gas well; as it increases, the open flow rate of the gas well also increases. Figures 19 and 20 illustrate the influence of absolute permeability on the unsteady IPR curve and unsteady productivity, respectively, of a gas well. When the production time is 100 days, as the absolute permeability increases, the gas well’s IPR curve is seen to shift to the right, and there is an increase in production. As the absolute permeability increases, the open flow of the gas well also rises. With a 100-day production time, there is an increase in absolute permeability from 0.5 to 5 mD, and the open flow rate of the gas well increases significantly from $10.3 \times 10^4$ to $64.1 \times 10^4$ m$^3$/d. Therefore, absolute permeability is the main factor influencing the unsteady-state productivity of gas wells in low-permeability gas reservoirs.

2.2.7. Influence of the Discharge Radius on the Unsteady-State Productivity of Gas Wells. Figure 21 illustrates the influence of the discharge radius on the open flow performance of a gas well. The figure shows that before the pressure wave reaches the boundary, the open flow performance of the gas well is unaffected by the discharge radius. The smaller the discharge radius, the sooner the pressure wave will reach the boundary, and the accelerated decline in production will occur sooner. Figure 22 shows the influence of the discharge radius on the unsteady IPR curve of a gas well. When the production time is 300 days, the pressure wave reaches the boundary of the discharge radius at 300 and 500 m. The earliest decline in output acceleration occurs at a discharge radius of 300 m, although it subsequently declines at a discharge radius of 500 m. With a 300-day production time, as the discharge radius increases, the IPR curve of the gas well shifts to the right, and there is an increase from $11.8 \times 10^4$ to $17.0 \times 10^4$ m$^3$/d in permeability on the unsteady IPR curve and unsteady productivity, respectively, of a gas well.
production from the gas well. Therefore, the unsteady productivity of gas wells in low-permeability gas reservoirs increases with the discharge radius.

2.2.8. Influence of Well Deviation Angles on the Unsteady-State Productivity of Gas Wells. Figure 23 shows the influence of the inclination angle on the open flow performance of a gas well. The figure reveals that over time, the open flows in highly deviated wells gradually decrease. The inclination angle is a significant factor for the entire production process of a gas well. As this angle increases, the open flow rate of the gas well also rises. Figures 24 and 25 illustrate the influence of the inclination angle on the unsteady IPR curve and unsteady productivity of a gas well. When the production time is 100 days, the IPR curve of the gas well is seen to shift to the right as the well inclination angle continues to increase from $20.2 \times 10^4$ to $42.8 \times 10^4$ m$^3$/d, resulting in a rise in production. When the well inclination angle is less than $45^\circ$, there is little change in the productivity of highly deviated wells compared with vertical wells. As the inclination angle increases, the open flow rate of the gas well first increases slowly; when the inclination angle exceeds $65^\circ$, a significant increase occurs in the open flow rate of the well.

2.3. Sequence of Main Controlling Factors of the Unsteady-State Productivity of Gas Wells. Because of the mutual influence of various sensitive factors, orthogonal experiments were used to conduct a multifactor analysis; this involved investigating the importance of each influencing factor and determining their order. According to the orthogonal principle and method, an orthogonal test was used to obtain the orthogonal table $L_18(3^7)$ with consideration of seven factors and three levels. A total of 18 tests are required to reflect the regularity obtained by $3^7 = 2178$ tests as a whole. In this study, the seven factors included the stress sensitivity coefficient, start-up pressure gradient, produced water–gas volume ratio, reservoir thickness, permeability, drainage radius, and well inclination angle. The assessment index was a single-well unblocked flow. Table 3 presents the design factors and levels according to which the orthogonal design was formulated. Table 4 shows the obtained orthogonal design scheme.
The visual analysis results of the orthogonal experiment are presented in Table 5 and Figure 26. The extreme differences in the influential factors directly reflect the factors’ impacts on gas well productivity. The test results reveal that the most important factors affecting the productivity of gas wells are the produced water–gas volume ratio, permeability, and stress sensitivity coefficient, while the reservoir thickness and start-up pressure gradient are key factors for the productivity of gas wells. The inclination angle and discharge radius are secondary factors on productivity. According to the results of an intuitive analysis, the degree of influence of the above seven influential factors on the open flow rate of a single well can be arranged in a descending order, as follows: volume ratio of produced water and gas, permeability, stress sensitivity factor, reservoir thickness, discharge radius, start-up pressure gradient, and inclination angle.
thickness, start-up pressure gradient, well angle, and discharge radius.

2.4. Evaluation of Unsteady-State Productivity of Example Wells. In Well F1 in the South China Sea, the main producing layer is located in the H1IIb layer. The diameter of the well is 0.10795 m, and it has a reservoir thickness of 17.42 m, an effective porosity of 17.4%, a well permeability test of 18.0 mD, and a gas saturation of 69.6%. The original formation pressure of the gas reservoir is 52.63 MPa, and the temperature of the gas reservoir is 144.29 °C. Production at the well commenced in May 2015. To date, the 70-month cumulative production period has resulted in a cumulative gas production of 764,446,200 m³, a cumulative water production of 8460.12 m³, and a cumulative oil production of 8820.55 m³.

Productivity tests were conducted in May 2015, and the tested unblocked flow rate was 367 × 10⁴ m³/d. A capacity test was conducted in July 2017, and a tested unblocked flow rate of 339 × 10⁴ m³/d was confirmed. In June 2018, a capacity test revealed a tested unblocked flow rate of 332 × 10⁴ m³/d. The unsteady-state productivity equation can be used to fit this well’s production data, and the fitting results are shown in Figures 27 and 28. The steady-state IPR curve of the gas well at each productivity test time point was calculated in accordance with the fitting results to obtain the corresponding open flow rate, as shown in Figure 29. This can be compared with the measured unblocked flow rate, as shown in Table 6.

An analysis of the above table reveals that the average error between the open flow calculated using the model and the measured unblocked flow rate is 4.6%, which is within the accuracy range allowed by the project. This confirms that the method has good adaptability to the well, and the derived productivity equation for low-permeability gas reservoirs has good potential for field application where it can exert a certain guiding effect on the production and development of actual gas reservoirs.

For the main control factors resulting from the research into the lifecycle productivity of Well F1, because the gas–water volume ratio of the well does not change much during the well’s lifecycle, the effect of the produced gas–water volume ratio on the well’s productivity remains largely unchanged during the early and mid-to-late production stages. Because the stress sensitivity coefficient decreases significantly with a reduction in formation pressure, the influence of the stress sensitivity coefficient on the productivity of gas wells during different periods was investigated. The analysis involved two time points (July 2015 and June 2018) and considered the difference in the productivity of a stress-sensitive gas well by both including and ignoring stress-sensitive flows, as presented in Table 7. It can be seen that as the production time increases, the influence of stress sensitivity on the open flow of the gas well also gradually increases.

3. CONCLUSIONS

1. This study established an unsteady-state productivity model for gas wells which considers the effects of start-up pressure gradient, stress sensitivity, and gas–water two-phase seepage and encompasses comprehensive factors affecting the productivity of single gas wells. The fitting of the actual production data of Well F1
confirmed that the within 5% of error meets the requirements for field application.

2. The water saturation is the main factor affecting the unsteady-state productivity of gas wells in low-permeability gas reservoirs. In this study, with a production time of 100 days, the water saturation increases from 45 to 85%, and the open flow of the gas well decreases significantly from 30.1 × 10^4 to 1.6 × 10^4 m^3/d, which is a decrease of 94.7%.

3. The higher the water production, the lower the permeability, the stronger the stress sensitivity, and the more significant the reduction in productivity. Therefore, for ultrahigh-temperature, high-pressure, low-permeability gas reservoirs, the productivity of a single gas well can be improved, to some extent, by reducing the water production of the well.

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Y.F.W.: Mainly responsible for the establishment of the production capacity model, paper writing, data analysis, and so on. P.G.: Providing directional guidance on the ideas of the thesis and completing the scientific inspection of the results of the thesis. J.J.R.: The main person responsible for the establishment and verification of the production capacity model and data selection and inspection, which is of great help to the completion of the thesis.

**Notes**

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