Research Article

Gas Hydrate Formation Risk and Prevention for the Development Wells in the Lingshui Gas Field in South China Sea

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Hydrate formation risk is an important challenge in the development of deep-water gas field. Considering the characteristics of the Lingshui (LS) gas field in the South China Sea and the difference of well structures, a model for calculating wellbore temperature and pressure in deep-water gas production well is proposed and verified by the field data. Combining the hydrate equilibrium models with varied gas components, the prediction method of hydrate formation region in deep-water gas well in the South China Sea is obtained. The hydrate formation regions under different operating conditions for a deep-water gas well in the South China Sea were given by the proposed model. The results show that no hydrate formation risk exists in the production operation, but the risk exists in the shut-in and testing operations. Meanwhile, the determination of the hydrate inhibitor injection parameters during the testing operation is studied, and the influence of the inhibitors’ injection concentration and pressure on preventing gas hydrates is analyzed. This work provides useful advice for the prediction and prevention of hydrate formation risk in the development of deep-water gas fields, especially in the South China Sea.

1. Introduction

The South China Sea is one of the four major oil and gas accumulations in the world, with about 23-30 billion tons of petroleum geological reserves, and accounts for one-third of China’s total oil and gas resources, 70% of which is located in the deep-water area of 1.537 million square kilometers [1]. Since 2014, CNOOC has started its own deep-water exploration in Qiongdongnan Basin of the South China Sea and made a historic breakthrough. However, due to the low temperature and high pressure near the mud line, and complex and changeable environment in deep water, the development of deep-water oil and gas fields faces the serious hydrate blockage problem in wellbore [2–5].

The Lingshui (LS) gas field in the South China Sea belongs to deep-water gas reservoir with bottom water, which has the water depth of 1252.2 m-1530.5 m, seabed temperature of 2°C-3.5°C, and reservoir pressure of 39.0-40.3 MPa. The low temperature and high pressure may cause the risk of hydrate formation in the wellbore [6–9].

Hydrate is a cage compound formed by the contact of hydrocarbon gas (methane, ethane, propane, etc.) and free water under the low temperature and high pressure [10]. In the development of deep-water oil and gas, the low-temperature and high-pressure environment on the seabed is a favorable condition for hydrate formation. Once hydrate is formed and further deposited in the wellbore which causes serious consequences, mainly the effective flow area of the string is reduced, the flow resistance is increased, and the flow safety of the wellbore is endangered. In serious cases, it even causes hydrate blockage, resulting in wrong measurement of pressure and flowmeter, and causing safety accidents such as pressure holding [11].

In addition, after the occurrence of hydrate blockage, the removal of hydrate plug can prolong the operation time and increase the operation cost [6]. As shown in Table 1, the hydrate accidents occurred in the process of deep-water oil and gas development in recent years [12–14].

In the development of deep-water oil and gas, hydrate formation in the wellbore has gradually attracted the attention
from scholars at home and abroad. Numbers of works on mass and heat transfer in wellbore have been done in previous studies. Ramey [15] first established a calculation model for wellbore temperature of steam injection wells by combining the heat transfer mechanism in the wellbore with the transient heat conduction of the surrounding formation. However, because the kinetic energy term and friction loss of fluid are not considered in this model, it can only be used for a single-phase flow. Satter [16] improved the Ramey model and considered the effect of fluid phase change on heat transfer. Willhite [17] proposed the classical formula of the total heat transfer coefficient in wellbore. Sagar et al. [18] improved the Ramey model according to the basic principles of thermodynamics and considered the effects of kinetic energy term and the Joule-Thomson effect, which can be applied to the multiphase flow. Guillot et al. [19] established the mechanism model of temperature field in cementing wellbore, which can predict the temperature field of wellbore and the surrounding formation. Most of the above studies assume that the wellbore diameter is infinitely small and are limited to the temperature calculation of steam injection wells under a steady flow. Hasan and Kabir [20–22] pointed out the deficiency of infinitesimal wellbore assumption and established a finite wellbore temperature calculation model which is suitable for the multiphase flow, unstable flow, and other conditions by using Sagar’s empirical formula. Although the model is widely accepted, the model used an empirical method to deal with the water content of the fluid in the string and did not explain the internal mechanism of heat transfer of gas-liquid two-phase flow. Sun et al. [23, 24] considered the different components in the wellbore pressure management and established a group of multicomponent multiphase flow-governing equations and temperature field equations in deep-water wellbore, which laid the foundation for the calculation of temperature and pressure field in deep-water wellbore. Considering wellbore structure, string structure, operation conditions, and other factors, Wang et al. [25, 26] comprehensively established the calculation model of temperature and pressure field of deep-water wellbore and the model of hydrate formation and deposition plugging in string. On the basis of systematically revealing the mechanism of hydrate deposition and plugging in deep-water gas wells, they first proposed the hydrate prevention method of allowing formation and preventing plugging, saving hydrate inhibitor by more than 60%. This method has gradually become the main reference method in the industry.

However, the traditional hydrate prediction model of deep-water gas well is mostly aimed at predicting the hydrate formation area in the wellbore under a single working condition and ignores the throttling effect caused by high-speed gas flow in the wellbore, so there is a certain error in predicting the hydrate formation area in the wellbore. In addition, there is no systematic study on the hydrate problem under different conditions in the process of deep-water gas field development. In this paper, the hydrate problem in the development of deep-water gas field is deeply studied, and the calculation model of wellbore temperature and pressure field is established. Considering the hydrate phase transition and throttling effect, the theoretical research on the quantitative prediction of hydrate formation area in deep-water wellbore is systematically carried out, and the quantitative prediction model of hydrate formation area is established. The model can realize the quantitative prediction of hydrate formation region in deep-water wellbore under different working conditions and reveals hydrate formation risk under different working conditions in the process of deep-water gas field development. It provides theoretical and technical support for the safe and efficient development of the Lingshui gas field in the South China Sea.

2. Prediction Theory of Hydrate Formation in Deep-Water Wellbore

2.1. Calculation Model of Wellbore Temperature and Pressure Field in Deep-Water Development. In the development of deep-water gas field, the calculation of wellbore temperature and pressure field distribution is the basis of regional prediction of hydrate formation. With known temperature and pressure distribution in the production string, the hydrate formation area in the wellbore can be accurately judged, and the foundation of the hydrate inhibitor program can be laid. In the current production process, only the temperature and pressure at the wellhead and bottom of the well can be measured. In order to obtain the temperature and pressure distribution in the whole production string, the calculation model must be established and solved according to the actual situation and theoretical knowledge. The multiphase flow in the deep-water gas wellbore has the following characteristics: the annular mist flow often appears in the wellbore; the gas-liquid distribution changes sharply; the mass transfer and heat transfer law is complex. The traditional temperature field model does not consider the enthalpy change caused by the volume change of gas and ignores the natural convection heat transfer between the tubing and casing. Therefore, changing the calculation principle of energy conservation only takes heat transfer as the research object and takes the enthalpy change of gas in the process of flow as the research object. Considering the throttling effect and the work done by volume change of high-speed gas flow, this paper establishes the calculation model and the solution method of wellbore temperature and pressure field.

| Date   | Region       | Water depth (m) | Hydrate formation region | Location of hydrate blockage | Time spent in plug removal |
|--------|--------------|-----------------|--------------------------|-----------------------------|---------------------------|
| 1998   | Shetlands    | 838.2           | 0-838.2                  | 594.4-838.2                 | >7 h                      |
| 2010   | Mexico       | 1722.9          | 0-2144                   | 850-2144                    | >11 d                     |
| 2012   | Campos Basin | 2788            | 0-3000                   | 1715-1798                   | >4 h                      |
2.1.1. Basic Assumptions

(1) The temperature and pressure of the fluid flowing into the pay zone remain constant.

(2) The fluid in the pay zone flows in one dimension in the pipe string, and the physical parameters of the same section are the same.

(3) Under the flow condition, the heat transfer in the string (from the inner wall of the tubing to the second interface) is stable; in a static state, the heat transfer in the string is unsteady.

(4) The formation heat transfer is unsteady.

(5) Geothermal gradient is known, and formation temperature is a linear function of well depth.

(6) Oil tube and casing are concentric.

2.1.2. Establishment of Temperature Field in Wellbore.

In the process of gas well production, gas or a small amount of water and condensate carried by gas goes from the bottom of the well to the wellhead at high speed. Due to the different string structure at different depths, the energy conservation equation can be divided into two parts.

The energy conservation equation [27] in the string below the mud line is

\[ \frac{1}{U_{t0}} = \frac{r_{to}}{r_{ti} h_{to}} + \frac{r_{ti}}{k_t} \left( \frac{\ln (r_{to}/r_{ti})}{H} + \frac{1}{h_t + h_i} \right) + \frac{r_{ti}}{k_{cas}} \ln \left( \frac{r_{co}/r_{ci}}{k_{cas}} \right) + \frac{r_{ti}}{k_{cem}} \ln \left( \frac{r_{wb}/r_{co}}{k_{cem}} \right), \]

where \( h_{to} \) is the heat convection coefficient between fluid and tubing, W/(m²·K); \( k_t \) is the thermal conductivity of the tubing, W/(m²·K); \( h_i \) is the convective heat transfer coefficient in the annulus, W/(m²·K); \( r_{to} \) is the outer radius of the casing; \( r_{ti} \) is the inner radius of the casing; \( m; r_{co} \) is the outer diameter of the cement ring, m; and \( k_{cem} \) is the thermal conductivity of the cement ring, W/(m·K).

The energy conservation equation [28] in the string above the mud line is

\[ \frac{2 r_{go}}{v r_{ti}^3} \left( T_{sea} - T_f \right) - \frac{\partial}{\partial z} \left[ \left( H + g z \cos + \frac{1}{2} f v^2 + \frac{f^2}{2d} \right) \right] = \frac{\partial}{\partial t} \left[ \left( C_p T_f + g z \cos + \frac{1}{2} f v^2 \right) \right], \]

where \( r_{to} \) is the outer radius of the riser, m; \( T_{go} \) is the total heat transfer coefficient based on the outer surface of the riser, m²·K/W; \( T_{sea} \) is the seawater temperature, K; and \( f \) is the wellbore friction coefficient.

\( H \) is the gas enthalpy, which is the biggest difference between the above energy conservation equation and the previous energy conservation equation for calculating wellbore temperature field. In the energy conservation equation, due to the high gas velocity, the throttling effect exists at the variable diameter of the production string. Because of gas compressibility, the change of gas volume will cause the change of enthalpy. Therefore, the internal energy and flow work of gas are comprehensively considered, which meets the requirements of throttling effect and gas expansion caused by the change of pipe diameter.

The enthalpy is calculated as follows:

\[ H(p, T) = \int_{T_0}^{T_f} C_p dT + \int_{P_0}^{P_f} V(1 - T^\beta) dp, \]

where \( V \) is the specific volume, m³/kg; \( T_0 \) is the temperature of the triple point, K; \( P_0 \) is the pressure at the triple point, Pa; \( C_p \) is the specific heat capacity, J/(kg·K); and \( \beta \) is the coefficient of thermal expansion, 1/K.

Transforming the above expression into differential expression can be easily brought into the temperature field equation for solution:

\[ dH = C_p dT + \left[ V - T \left( \frac{\partial V}{\partial T} \right)_p \right] dp. \]

2.1.3. Establishment of Pressure Field Equation in Wellbore.

The bottom hole is set as the coordinate origin, and the fluid
flow direction is positive. The established coordinate system is shown in Figure 1.

In the control volume as shown in Figure 1, the following pressure field equation must describe the process of gas flowing from bottom to wellhead along the wellbore:

$$\frac{\partial}{\partial t} (Av) + \frac{\partial}{\partial t} (Apv^2) + Apg \cos \alpha + \frac{d(Ap)}{dz} + \frac{d(AF_c)}{dz} = 0,$$

(6)

where $A$ is the circulation area, $m^2$; $p$ is fluid pressure, Pa; $F_c$ is the friction loss along the way, Pa; $\alpha$ is the inclination angle of the well, $^\circ$; $\rho$ is the fluid density, kg/m$^3$; and $v$ is the fluid velocity, m/s.

2.1.4. Model Solving Process. In the prediction model of pressure and temperature in deep-water wellbore established above, fluid flow and heat transfer process influence each other, which makes the established model highly nonlinear. Therefore, numerical solution is needed. In this paper, the finite difference method is adopted, and the solving steps are shown in Figure 2.

1. The string is divided into several unit sections, and each unit section is short enough, so that the gas velocity, gas density, and pipe wall roughness in each unit section are constant.

2. The inlet parameters (temperature, pressure, and volume fraction of each phase) and the ambient temperature at the $n$th time of unit $i$ are known.

3. Suppose that the outlet temperature and outlet pressure $T_{out}$ and $p_{out}$ at the $n$th time of the unit section.

4. Take the average temperature and pressure of this section as $p = (p_{in} + p_{out})/2$, $T_i = (T_{in} + T_{out})/2$, and calculate the gas density, pipeline friction pressure drop, and gravity pressure drop of this unit section according to $p$ and $T_i$.

5. The outlet temperature and pressure of the unit are obtained by substituting the above parameters into the comprehensive model of flow and heat transfer and compared with the assumed temperature and pressure. If the error is within the allowable range, the calculation is completed; otherwise, the temperature and pressure value obtained from the calculation is taken as the assumed value, and the above calculation process is repeated until the accuracy requirements are met.

6. The calculated outlet temperature and pressure at the $n$th time of the $i$ unit section are taken as the inlet parameters at the $n$th time of the next unit section $(i + 1)$. The outlet temperature and pressure at the $n$th time of the $i + 1$ unit section can be calculated in the same trial process.

7. Taking the temperature and pressure value at the $n$th moment of each element segment as the initial value, the parameters at the $n + 1$ moment can be obtained through the same trial calculation process.

During shut-in, the pressure in the string is the sum of the wellhead pressure and the static pressure of the gas column. The initial condition of temperature is the temperature value of each node in the string during flow. The boundary condition is that the fluid temperature in the string is the same as the formation temperature. During the flow test, the initial pressure in the string is caused by the back pressure of the surface wellhead and the gravity of the fluid in the wellbore, and the initial temperature is the ambient temperature.

\[
\begin{align*}
    p(i, 0) &= p_0 + gh_i, \\
    T(i, 0) &= T_{ei},
\end{align*}
\]

(7)

where $h_i$ is the vertical depth, m; $T_{ei}$ is the ambient temperature at depth $h_i$, which is the temperature of the environment around the wellbore, K; and $P_0$ is the wellhead back pressure, Pa.

The external temperature is very important to solve the model. The vertical distribution of seawater temperature in the South China Sea can be divided into three layers: the mixing layer, which is generally within 100 meters of the ocean surface, has uniform water temperature and small vertical gradient due to strong mixing caused by convection and wind waves; thermocline, which is below the mixing layer and above the constant temperature layer, has the water temperature decreasing sharply with the increase of depth, and the large vertical gradient of water temperature; and the isothermal layer, which is below the thermocline to the bottom of the sea, has the water temperature generally changes very little, about 2-6°C. Gao et al. [29] obtained the relationship function between seawater temperature and water depth through general formula fitting.

When the water depth is more than 200 m,

$$T_{sea} = a_1 + \frac{a_2}{(1 + (e(h + a_0)/a_3))}, \quad h > 200 \text{ m},$$

(8)
where $a_1 = 39.398$, $a_2 = 37.091$, $a_0 = 130.137$, and $a_3 = 402.732$; $T_{sea}$ is the seawater temperature, °C; and $h$ is the sea depth, m.

When the water depth is less than 200 m, the temperature distribution is related to seasons.

Spring: $T_{sea} = \frac{T_s(200 - h) + 13.68h}{200}$, $0 \leq h < 200$ m,

Summer: $T_{sea} = T_s$, $0 \leq h < 200$ m,

Autumn: $T_{sea} = \frac{T_s(200 - h) + 13.7(h - 20)}{180}$, $20 \leq h < 200$ m,

Winter: $T_{sea} = T_s$, $0 \leq h < 200$ m,

$T_{sea} = \frac{T_s(200 - h) + 13.7(h - 50)}{150}$, $50 \leq h < 200$ m,

$T_{sea} = \frac{T_s(200 - h) + 13.7(h - 100)}{100}$, $100 \leq h < 200$ m,

(9)

where $T_s$ is the surface temperature of seawater, °C.

Using the proper formula of seawater temperature field, the seawater temperature of different water depths can be obtained. Combined with the geothermal gradient, the ambient temperature distribution of the whole wellbore from the wellhead to the bottom can be obtained.

2.1.5. Model Validation. The model is verified by the measured data of a deep-water gas well in the South China Sea. The well is a vertical well with the depth of 3474 m, the bottom hole temperature of 90.5°C, and the original formation pressure of 39.0 MPa. The measured wellhead temperature and pressure under different test production and the calculation results of this model are shown in Table 2. It can be seen from the table that the calculated results of the model are in a good agreement with the field-measured data. The maximum absolute error of the calculated temperature is within 7.7°C, and the maximum absolute error of the calculated pressure is within 1.2 MPa, which indicates that the model can accurately predict the wellbore temperature and pressure distribution in the testing process of deep-water gas wells.

2.2. Theoretical Model of Phase Equilibrium Conditions for Gas Hydrate Formation. According to the hydrate phase equilibrium model proposed by Javanmardi and Moshfeghian [30], considering the influence of different gas components (methane, ethane, propane, butane, carbon dioxide, nitrogen, etc.) on gas hydrate phase equilibrium conditions, the hydrate phase equilibrium conditions can be obtained as follows:

$$\frac{\Delta \mu_0}{RT_0} = \int_{T_0}^{T} \frac{\Delta H_0 + \Delta C_P (T - T_0)}{RT^2} dT + \int_{P_0}^{p} \frac{\Delta V}{RT} dP$$

where $\Delta \mu_0$ is the chemical potential difference between the hollow hydrate crystal lattice and pure water in the standard state; $T_0$ and $P_0$ are the temperature and pressure in the standard state, respectively; and $T_0 = 273.15$ K, $P_0 = 0$, $\Delta H_0$, $\Delta V$, and $\Delta C_P$ are the specific enthalpy difference, specific tolerance, and specific heat tolerance of the hollow hydrate lattice and pure water, respectively. For $\ln (f_w)^{\theta_i}$, if inhibitor is added, then $\ln (f_w) = \ln x_w$, if inhibitor, $x_w$ and $y_w$ are the
3. Results and Discussion

Using the above model, the risk of hydrate formation in a well of Lingshui gas field in the South China Sea is predicted and analyzed. The well is a deep-water gas well, and its basic parameters are shown in Table 3. The components of the produced gas are shown in Table 4.

According to the calculation model of hydrate phase equilibrium in Section 2.2, the hydrate phase equilibrium conditions with and without water salinity are predicted, as shown in Figure 4. From the figure, comparing to the case without water salinity, the hydrate formation with water salinity requires lower temperature and higher pressure. This is mainly because the mineral ions (Na⁺, K⁺, Ca⁺, Cl⁻, etc.) play the role as salt inhibitors, which can inhibit the formation of gas hydrate. However, in the actual engineering application, the field engineer must consider the safety factor when they design the hydrate flow assurance scheme. Therefore, for the sake of the safety factor, the salinity of water is not considered when calculating the hydrate formation region in the wellbore.

3.1. Hydrate Prediction under Normal Production Conditions. Normal production condition is the main process of deep-water gas well development, which can effectively flow to the wellhead by controlling the production pressure difference. Through the calculation of temperature-pressure field and hydrate phase equilibrium conditions in the wellbore during normal production, the hydrate formation risk under different production rates can be obtained, as shown in Figure 5. It can be seen from the figure that the temperature in the wellbore gradually decreases with the decrease of production during normal production, and the wellhead temperature distribution during the whole production period is between 29.8°C and 82.1°C. By comparing the hydrate phase equilibrium curves, it can be found that the temperature in the wellbore during the whole normal production period is higher than the critical temperature of hydrate formation under the corresponding wellbore pressure. Therefore, during normal production, the temperature and pressure in the wellbore do not meet the hydrate formation conditions. No risk of hydrate formation is observed, and no hydrate prevention measures are required.

3.2. Hydrate Prediction under Shut-in Condition. After the test of deep-water gas well is completed, the gas well test often needs to be shut in at the subsea wellhead (i.e., shut-in), and the riser and auxiliary structure above the mud line are removed. After a period of time in the future, the process of transferring exploration well to development well can continue to open the well for production. Taking a well as an example, Figure 6 shows the variation of temperature field and hydrate formation region in the wellbore at different times after well shut-in. It can be seen from the figure that the temperature in the wellbore gradually decreases with time after shut-in. When the well is shut in for about 4.7 h, the temperature in the wellbore begins to meet the temperature conditions required for hydrate formation, which means that the hydrate formation region begins to appear in the wellbore, and the hydrate formation region in the wellbore gradually increases with the decrease of temperature in the wellbore. When the temperature in the wellbore is equal to the formation environment temperature, the hydrate formation region in the wellbore reaches the maximum. After shut-in for 29.7 hours, the hydrate formation region in the wellbore reaches the maximum, from mud line to 457 meters below mud line (1477 m-1934 m). In addition, the closer to the mud line, the wider radial area between wellbore temperature curve and phase curve, which means the greater the subcooling of hydrate formation, the easier the hydrate formation, and the greater the risk of hydrate formation. The

| Index | Production (10⁴ m/d) | Wellhead temperature (°C) | Wellhead pressure (MPa) |
|-------|-----------------------|---------------------------|------------------------|
|       | Measurement Prediction Absolute error Measurement Prediction Absolute error |
| 1     | 48.3                  | 19.0                      | 12.4                   | -6.6                   | 28.9                  | 29.5                   | 0.6                     |
| 2     | 74.3                  | 17.6                      | 16.2                   | -1.4                   | 27.1                  | 27.6                   | 0.5                     |
| 3     | 123.7                 | 18.2                      | 20.8                   | 2.6                    | 21.6                  | 22.8                   | 1.2                     |
| 4     | 160.6                 | 17.9                      | 25.6                   | 7.7                    | 16.8                  | 17.4                   | 0.6                     |
farther away from the mud line, the narrower the radial area between the temperature curve and the phase curve, and the less likely the hydrate is to be formed. Below 457 m away from the mud line, the temperature and pressure in the wellbore do not meet the conditions of hydrate formation, and the risk of hydrate formation disappears. Aiming at the risk of hydrate formation under shut-in condition, the installation position of downhole safety valve can be designed according to the predicted hydrate formation region. For the sake of safety factor, it is suggested that the downhole safety valve should be designed 100 m below the hydrate formation region. At the same time, it is recommended to close the downhole safety valve first, then inject inhibitors through the Christmas tree, and fill the wellbore above the downhole safety valve with inhibitors, so as to avoid hydrate hazards in the wellbore after shut-in.

3.3. Hydrate Prediction under Test Conditions

3.3.1. Prediction of Hydrate Formation Region. Test condition is the key stage to obtain reservoir parameters, evaluate gas reservoir reserves, and formulate development plan. The main difference between deep-water gas well testing and onshore gas well testing is that the test string above the mud line is located in the riser in deep-water low-temperature environment, which causes the fluid in the test string to be cooled through a long low-temperature seawater section, which means that there will be a low-temperature

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**Table 3: Basic data of the case well.**

| Parameters                | Value   | Parameters                | Value   |
|---------------------------|---------|---------------------------|---------|
| Water depth               | 1466 m  | 13-3/8" conduct depth     | 2913 m  |
| Well depth                | 3501 m  | 9-5/8" conduct depth      | 3501 m  |
| Formation temperature     | 95.5°C  | Test string inner diameter| 85.6 mm |
| Original formation pressure| 40.2 MPa| Relative density of natural gas | 0.644 |
| 36" conduct depth         | 1539 m  | Formation water salinity  | 27.785 g/L |
| 20" conduct depth         | 2230 m  | Formation water density   | 1.017 g/cm³ |

**Table 4: Gas composition.**

| Components | CH₄ | C₂H₆ | C₃H₈ | i-C₄H₁₀ | n-C₄H₁₀ | i-C₅H₁₂ | n-C₅H₁₂ | C₆+ | CO₂ | N₂ |
|------------|-----|------|------|---------|---------|---------|---------|-----|-----|----|
| Mole fraction (%) | 88.91 | 5.02 | 1.78 | 0.39 | 0.49 | 0.24 | 0.17 | 1.82 | 0.58 | 0.60 |
and high-pressure well section in the string, which is easy to meet the low-temperature and high-pressure conditions for hydrate formation. The temperature and pressure field-prediction model established in this paper can be used to calculate the temperature and pressure distribution in the wellbore under different test production. By comparing the temperature-pressure curve and hydrate phase equilibrium curve in the wellbore, the hydrate formation region in the wellbore under different testing stages can be judged, as shown in Figure 7. It can be seen from the figure that the temperature in the wellbore gradually decreases with the decrease of testing rates, which is mainly caused by the decrease of fluid velocity and more sufficient heat exchange with the surrounding environment. By comparing the hydrate formation regions under different testing rates, it is found that when the testing rate is reduced to about 1.3 million m$^3$/d, the risk of hydrate formation begins to appear in the wellbore; with the decrease of testing rates, the intersection area of temperature pressure curve and hydrate equilibrium curve in wellbore increases gradually, which indicates that the hydrate formation region in wellbore increases with the decrease of testing rates.

3.3.2. Prevention of Hydrate by Thermodynamic Inhibitors. Combined with the prediction results of hydrate formation region during deep-water gas well testing, the injection parameters of thermodynamic inhibitors to prevent hydrate formation can be designed.

(1) Determination of Inhibitor Injection Location. During the testing process of deep-water gas well, the injection position of hydrate inhibitor includes the surface nozzle manifold, the mud surface underwater test tree, and a certain depth below the mud surface. Among them, a certain depth below the mud surface needs to be calculated. In order to ensure that the hydrate inhibitor can cover all the well sections that may generate hydrate after injection, the deepest point of the hydrate formation region under the most dangerous situation is selected as the injection point of the inhibitor. The injected inhibitor can be carried up by the produced gas and widely distributed in the hydrate formation region, so as to inhibit the formation of hydrate.

(2) Determination of Inhibitor Injection Concentration. Aiming at the risk of hydrate formation under test conditions, methanol or glycol is mainly injected to inhibit hydrate formation. By calculating the hydrate phase equilibrium conditions under different injection concentrations of methanol and ethylene glycol, the hydrate inhibitor injection plates under different test yields can be obtained, as shown in Figures 8 and 9. It can be seen from the figure that with the increase of test production and inhibitor injection concentration, the wellbore temperature pressure curve and hydrate phase equilibrium curve gradually deviate, indicating that the hydrate formation region in the wellbore decreases at this time. At the same time, by comparing the inhibition effect of methanol and ethylene glycol, it can be concluded that the inhibition effect of methanol on hydrate formation is slightly better than that of ethylene glycol, but methanol has the disadvantages of medium toxicity and volatility. In the field test process, methanol or glycol can be selected as hydrate inhibitor according to the actual demand.

(3) Determination of the Injection Pressure. The surface chemical injection pump pumps hydrate inhibitors into the wellbore through the chemical injection pipeline in the umbilical of the underwater test tree. Under different test conditions, the pressure distribution in the wellbore will change significantly. Therefore, it is necessary to calculate the injection pressure of surface chemical injection pump according to the pressure in the wellbore at the injection point during the actual operation.

During the injection of inhibitors such as methanol and glycol, the minimum pressure of the surface injection pump is calculated as follows:

$$P_z \geq P_z + P_j + P_f - P_h,$$

where $P_z$ is the minimum injection pressure of the injection pump, Pa; $P_z$ is the pressure in the wellbore at the injection point, Pa; $\Delta P_f$ is the frictional pressure drop along the way, Pa; $\Delta P_j$ is the local pressure loss at the injection point, Pa; and $\Delta P_h$ is the hydrostatic pressure of the inhibitor, Pa.

The frictional pressure drop along the way $\Delta P_f$ is related to the friction coefficient and inhibitor injection rate, which can be calculated by the following formula:

$$P_f = \frac{1}{2} \lambda \frac{v_i^2}{D} \times H,$$

where $\lambda$ is the friction coefficient; $\rho_1$ is the density of the inhibitor, kg/m$^3$; $v_i$ is the inhibitor injection speed, m/s; $D$ is the diameter of inhibitor injection pipeline, m; and $H$ is the inhibitor injection position, m.

Figures 10 and 11 are injection pressure charts of methanol and glycol under different testing rates and water-cut, respectively. It can be seen from the figure that under the
Figure 5: Hydrate formation region prediction at production period.

Figure 6: Hydrate formation region prediction at shut-in period.
same water-cut condition, with the increase of test output, the inhibitor injection concentration decreases and the water yield increases. Affected by both, the pump pressure required for inhibitor injection first increases and then decreases. Under the same testing rates, with the increase of water-cut, the inhibitor injection volume increases, and the pump pressure required for inhibitor injection increases gradually. The injection pressure of ethylene glycol is higher than that of methanol because of the higher density and viscosity of ethylene glycol, and the larger injection amount of inhibitor at
high water-cut; but at low water-cut, the injection volume of inhibitor is small, and the friction along the way has little effect on the pressure drop, so the injection pressure of ethylene glycol is lower than that of methanol. Therefore, ethylene glycol is recommended to prevent hydrate at low water-cut, while methanol is recommended to prevent hydrate at high water-cut.

3.3.3. Other Hydrate Control Measures. In addition to the injection of thermodynamic inhibitors, the current measures
to prevent hydrate formation include injections of kinetic inhibitors, antipolymerization agents, and thermal insulation technology. Both kinetic inhibitor and antipolymerization agent allow hydrate to form and transport oil and gas in the form of slurry. This method requires low concentration of inhibitors, which is mainly used in submarine oil pipeline or oil-water-mixed pipeline, but not in deep-water oil and gas well. The thermal insulation technology is to insulate the wellbore to reduce the heat loss, improve the fluid temperature, and reduce the hydrate formation region. It is a very promising hydrate prevention method. At present, the wellbore thermal insulation technologies used in domestic and foreign oilfields mainly include gas thermal insulation, VIT thermal insulation, VIC thermal insulation, thermal insulation, and fluid thermal insulation.

4. Conclusion

Considering the characteristics of Lingshui gas field in the South China Sea, based on the calculation model of temperature and pressure field in deep-water wellbore and hydrate phase equilibrium conditions, this paper establishes a quantitative prediction method of hydrate formation region, analyzes the hydrate risk existing in the wellbore under different production stages in the development of Lingshui gas field in the deep-water region, and obtains the following understandings:

1. In the normal production process, the temperature in the wellbore is much higher than the critical temperature needed for hydrate formation. No risk of hydrate formation in the wellbore is observed, and hydrate prevention measures are not needed in the whole normal production stage.

2. Under the shut-in stage, when the well is shut-in for a certain time, the risk of hydrate formation rises up in the wellbore. The longer the shut-in time, the larger the hydrate formation region exists in the wellbore. For the sake of safety factor, it is suggested that the downhole safety valve should be installed 100 m below the maximum hydrate formation region. At the same time, it is recommended to close the downhole safety valve first and then fill the wellbore above the downhole safety valve with inhibitors through the Christmas tree, in order to avoid hydrate hazard in the wellbore after shut-in.

3. Under the testing stage, when the testing rates are lower than the critical production, hydrate formation risk exists in the wellbore. Under the testing stage, the hydrate formation region in the wellbore mainly distributes in the seawater section and the hydrate formation region gradually increases with the decrease of testing rates. The increase of hydrate inhibitor injection concentrations is beneficial to reduce the hydrate formation region in the wellbore. The pressure required by the hydrate inhibitor injection pump is affected by test production, water-cut, inhibitor type, and other factors.

Data Availability

The data in this paper is from our project.
Conflicts of Interest

The authors declare that they have no conflicts of interest.

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