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Investigation on Flow Characteristic of NGS through an Annulus

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Abstract. In the transportation of natural gas hydrate slurry, problems such as blockage and sedimentation caused by hydrates aggregation are often encountered. In addition, the risk control of hydrate decomposition is particularly important. Therefore, in order to investigate the flow characteristics and morphology of hydrate slurring, the phase equilibrium model of natural gas hydrate in water-based drilling fluid system is established. It is found that substances such as sodium chloride, potassium chloride, and glycerol all cause a decrease in the temperature at which hydrates are formed. Then, the temperature and pressure distribution in annulus tube are calculated based on the mixed flow model. The results show that the NGS through an annulus could be decomposed under most conditions involved in this paper. The higher the volume concentration of the NGS, the lower the temperature in annulus tube. Because the greater the hydrate concentration, the more hydration decomposition along the process, and the decomposition of the hydrate is endothermic, so the decomposition of the hydrate will make the temperature in annulus tube lower. Under the condition that the hydrate concentration is 10% and the inlet flow rate of the drilling fluid is 160 L/s, the inlet temperature of the drilling fluid has a great influence on the temperature in the ring air pipe. When the inlet temperature is relatively low, it is in the stable state of hydrate at the bottom of well and above part of the area. Therefore, controlling the temperature of drilling fluid entry would be a better measure to control the amount of hydrate decomposition.

1. Introduction

With the tendency of petroleum exploitation moving to deep-water, NGH (natural gas hydrate) formation and deposition in the pipe have been a major hazard of subsea transportation system due to blockage[1]. Many foreign institutions have studied the phase equilibrium and formation of NGH, in order to develop a methods to prevent blockage of hydrates in pipes. Injecting hydrates inhibitor is a most common way to prevent hydrates forming by shifting the phase equilibrium curve to more severe conditions[1-2]. More detailed information about hydrates inhibitor, example for KHIs and AAs can be found elsewhere[3-5]. While this traditional technique for preventing NGH formation brings great costs, insulation is difficult to apply to pipeline systems in deep-sea petroleum industry due to technical limitation[6]. One of the new techniques is to disperse natural gas hydrates in the form of solid particles in a multiphase stream to form a slurry for transport. Actually, researchers have performed a great deal of work on GNS(gas hydrates slurry) formation and flow characteristics. Joshi observed the formation of a small quantity of hydrates might immediately lead to slug flow onset in high water cut producing oil pipelines, and established the modelling of gas hydrate formation[6].



Zerpa et al. established a hydrodynamic slug model which showed that factors such as hydrates volume fraction, hydrates aggregation affect the slug characteristics significantly[7]. Then, a series of hydrates slurry flow experiments was conducted in a high pressure flow loop with visual window. Through this flow loop, hydrate slurring flow experiments in natural gas + diesel oil + water system were performed for a range of water cuts(30-100%) and initial flow rates(1600-2400kg·h⁻¹). Peng et al. investigated the flow characteristics and morphology of hydrate slurring in these systems containing anti-agglomerate[3, 8-9]. As a complex suspension system, the influence of aggregation and breakage of the hydrates particles under flow condition is critical and could not be ignored. This paper mainly studies the flow field of hydrate slurring in the whole process from the bottom of the well to the wellhead. Because the temperature in the annular tube is higher than the ambient temperature, hydrate particles in natural gas +diesel oil + water system may decompose. Whether the hydrate particles decompose is related to the temperature and pressure conditions in the annulus tube. Therefore, to research the aggregation and breakage of the hydrates particles, it is mainly to calculate the temperature and pressure in the annulus tube. As it involves the decomposition of hydrate particles, solid - liquid two-phase flow or solid - liquid - gas three-phase flow would occur in the whole system, the solution of multiphase flow is very complicated, especially solid - liquid - gas three-phase flow. At present, there are two basic ways to solve the multiphase flow, one is the mixed flow model and the other is the split phase model. For this paper, the mixed flow model is adopted.

2. The formation temperature of natural gas hydrate slurry

2.1. The formation temperature of natural gas hydrate

According to the thermodynamic model theory, chemical phase difference $\Delta\mu^H$ between the fully filled hydrate phase(denoted as H) and the empty hydrate phase can be calculated by gas adsorption model:

$$\Delta\mu^H = \mu^\beta - \mu^H = -RT \sum_{i=1}^2 v_i \ln(1 - \sum_{j=1}^{N_c} \theta_{ij}) \quad (1)$$

In which, R is general gas constant; T is hydrate formation temperature; v_i is the ratio of the number of holes in the i -type of hydrate lattice to the number of water molecules; the occupancy rate of i -type holes by j component molecules θ_{ij} is:

$$\theta_{ij} = \frac{C_{ij} f_j}{1 + \sum_{j=1}^{N_c} C_{ij} f_j} \quad (2)$$

Where C_{ij} is Langmuir constant, the unit is 1/kPa. f_j is the fugacity of the j component in the gas phase, the unit is kPa. And

$$C_{ij}(T) = \frac{a_{ij}}{T} \exp\left(\frac{b_{ij}}{T} + \frac{d_{ij}}{T^2}\right) \quad (3)$$

Where a_{ij} , b_{ij} , and d_{ij} are constants, the specific values can be found in the literature [10]. The definition of gas fugacity f_j is:

$$RT \ln\left(\frac{f_j}{p}\right) = \int_p^p V_{m,B} dp - RT \ln\left(\frac{p}{p^0}\right) \quad (4)$$

Substituting the van der Waals equation into the above equation to obtain the fugacity calculation formula:

$$\ln\left(\frac{f}{p}\right) = \ln\left[\frac{RT}{P(V_m - b)}\right] + \frac{b}{V_m - b} - \frac{2a}{RTV_m} \quad (5)$$

Where a , b are constants, and V_m is the molar volume of the gas under the pressure P and temperature T . f/p is the relative fugacity. Generally, the relative fugacity is between 0.8 and 1.2. The gas fugacity in the mixed state can be calculated using the Lewis-Randall rule. The right side of equation (1) can be expressed as:

$$\frac{\Delta\mu^W(T, P)}{RT} = \frac{\Delta\mu^W(T_0, 0)}{RT} - \int_{T_0}^T \frac{\Delta h_W}{RT^2} dT + \int_0^P \frac{\Delta V_W}{RT} dp - \ln x_w \quad (6)$$

Δh_W and ΔV_W is expressed as the molar coma and volume difference between the β phase and the W phase. It can be calculated using the following equations:

$$\Delta h_W = \Delta h_W^0 + \int_{T_0}^T \Delta C_{P_W} dT \quad (7)$$

In the calculation of the hydrate formation temperature, if the temperature higher than the freezing point, the molar ratio of water x_w is:

$$x_w = 1 - \sum_{j=1}^{N_c} x_j \quad (8)$$

Where x_j is the solubility of the gas molecules in water. And

$$x_j = f_j x_{0j} \exp\left(-\frac{\bar{V}_j(P-1)}{82.06T}\right) \quad (9)$$

$$x_{0j} = \exp\left(A_{0j} + \frac{B_{0j}}{T}\right) \quad (10)$$

Where A_{0j} and B_{0j} are constant, see the literature [11]. V_j is the partial molar volume constant of the component gas (60 for ethylene and 32 for other gases). This time, 5 series of components are choosed. its components are listed in the table 2. The hydrate formation temperature is calculated using the above formula method. The results are shown as figure1.

Table 1. The component of natural gas.

Series	CH ₄	C ₂ H ₆	C ₃ H ₈	i-C ₄ H ₁₀
A	1.00	0.00	0.00	0.00
B	0.95	0.03	0.01	0.01
C	0.90	0.08	0.01	0.01
D	0.85	0.13	0.01	0.01
E	0.80	0.18	0.01	0.01

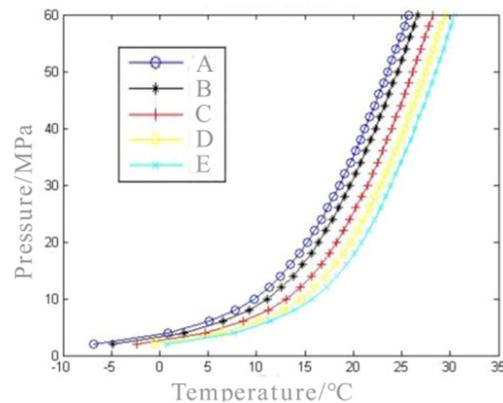


Figure 1. The hydrate formation temperature of 5 kinds of nature gas.

2.2. The formation temperature of hydrate in natural gas + diesel oil + water system

In the drilling fluid (here mainly referred to as water-based drilling fluid), there are clay, sodium chloride, potassium chloride, glycerine and the like. For clay, the formation temperature of natural gas hydrate is increased. In the literature [12], the influence of clay on the temperature of hydrate formation was studied. It was found that 4% concentration of clay caused the hydrate formation temperature to rise by about 0.8 °C. Substances such as sodium chloride, potassium chloride, and glycerol all cause a decrease in the temperature at which hydrates are formed. According to the literature [13], the commonly used hydrate inhibitor methanol has a greater influence on the hydrate formation temperature. When the methanol concentration is 10%, the hydrate formation temperature decreases more than 5 °C. The difference of hydrate formation temperature between in the drilling fluid system and in the pure water can be expressed by the following equation:

$$\Delta T = 112.3x_{in} + 2011.6x_{in}^2 - 6505.0x_{in}^3 \quad (11)$$

Where x_{in} is the total inhibitory ion concentration in the drilling fluid. The component mass concentrations of the four inhibitors are shown in table 2.

Table 2. Inhibitory components in four drilling fluids.

	NaCl(%)	KCl(%)	glycerine(%)	x_{in} (%)
1	1.00	0	0	0.0060
2	0	1.00	0	0.0048
3	0	0	1	0.0020
4	1	1	1	0.00942

Taking a natural gas as an example, the hydrate formation temperature in the different drilling fluid was calculated. And the temperature is shown in figure 2. By comparison, it is known that under the same mass concentration, the highest temperature drop caused by NaCl, KCl and glycerol is NaCl, and the weakest is glycerol.

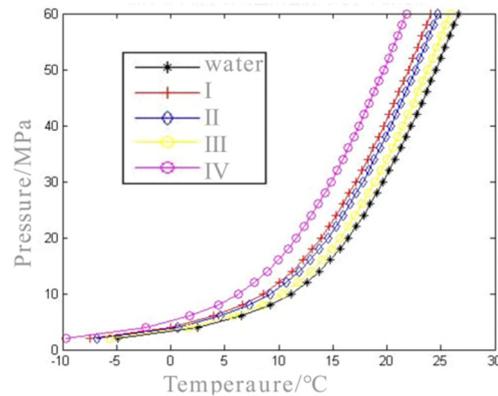


Figure 2. The hydrate formation temperature in drilling fluid and pure water.

3. Physical models of NGH through an annulus

The annular pipe is the annular space formed by the outer wall of the drill pipe and the inner wall of the casing or the inner wall of the riser. Single pressure gradient method is generally used for drilling. The following is a schematic diagram of drilling and the heat transfer model of annular pipe in seawater section.

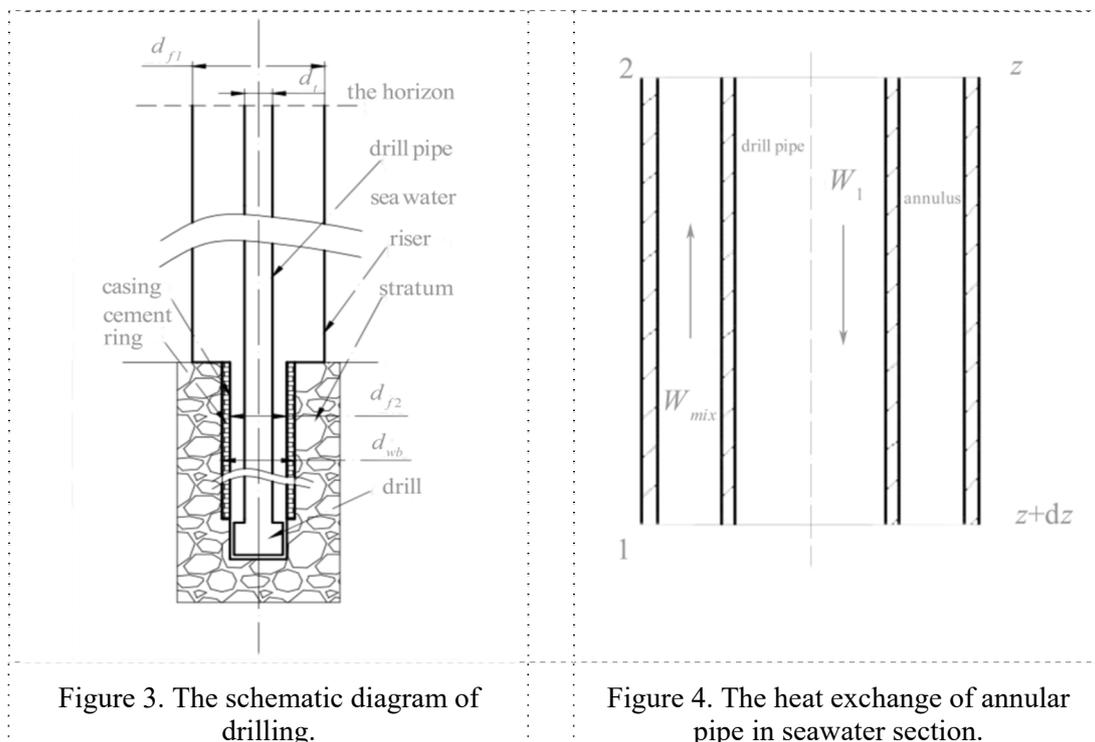


Figure 3. The schematic diagram of drilling.

Figure 4. The heat exchange of annular pipe in seawater section.

Taking micro-element Dz as the object, the energy flowing into the infinitesimal body is:

$$q_{(z+dz)} = W_{mix} C_{mix} T_{a1} \quad (12)$$

The energy that flows out of the infinitesimal is:

$$q_{(z)} = W_{mix} C_{mix} T_{a2} \quad (13)$$

It is assumed that the temperature of seawater and drilling fluid in the drill pipe is T_{sea} and T_t . The heat transfer coefficients of the fluid and the wall of the drill pipe is $1/A$, and the seawater casing is $1/B$. The energy exchanged between the fluid and the wall of the drill pipe and the wall of the seawater casing is denoted by Q_{ta} and Q_{wa} , respectively.

$$Q_{wa} = \frac{1}{A}(T_{sea} - T_a)dz \quad (14)$$

$$Q_{ta} = \frac{1}{B}(T_a - T_t)dz \quad (15)$$

Consider the heat absorbed by natural gas hydrate decomposition in the unit body is $Q_s = M_G \cdot \Delta H$. Among them, M_G is the decomposition rate of hydrate (kg/s). ΔH is the heat of decomposition of natural gas hydrate, which is taken as 70.04 KJ/mol. The decomposition rate is calculated using the model described in [14].

$$M_G = K_D A_S (P_D - P) V_B \quad (16)$$

Where K_D is the hydrate reaction rate constant, taken as 1×10^{-13} kg/(m² · Pa · s); A_S is the reaction specific area of the hydrate, taken as 6.682×10^4 m⁻¹; P_D is the phase equilibrium pressure; P is the pressure inside the annulus; V_B is the volume of the hydrate in the unit body. According to the principle of conservation of energy, there is:

$$W_{mix} C_{mix} T_{a1} - W_{mix} C_{mix} T_{a2} + Q_{wa} - Q_{ta} + Q_s = 0 \quad (17)$$

The two sides of the equation are simultaneously derived to obtain the equation:

$$\frac{d(W_{mix} C_{mix} T_a)}{dz} = \frac{Q_{ta} - Q_{wa} - Q_s}{dz} \quad (18)$$

By substituting Q_{ta} and Q_{wa} , the temperature equation of the fluid in the annulus can be obtained:

$$\frac{d(W_{mix} C_{mix} T_a + M_G \Delta H)}{dz} = \frac{1}{B}(T_a - T_t) - \frac{1}{A}(T_{sea} - T_a) \quad (19)$$

Similarly, the temperature field of the drilling fluid in the drill pipe is calculated as follows:

$$\frac{d(W_1 C_1 T_t)}{dz} = \frac{1}{B}(T_a - T_t) \quad (20)$$

In the equation, W_1 is the mass flow rate of the drilling fluid, W_{mix} is the total mass flow rate of the drilling fluid and the hydrate particles, C_{mix} is the specific heat of the mixed fluid in the annulus tube, and C_1 is the specific heat of the drilling fluid. The total pressure loss is calculated using the formula recommended in [15].

4. Solution to the temperature and pressure equation

4.1. Basic parameters

The temperature at the entrance of the drill pipe is known and can be assumed to be different according to different conditions. Ignoring the effect of heat generated during drilling on the drilling

fluid temperature, it can be considered that the temperature at the bottom of the well is $T_a = T_i$. The pressure at the bottom of the well is 35 MPa. The dimensions of drill and annulus is shown as table 3.

Table 3. Dimensions of drill pipe and annulus.

	inner diameter(mm)	outer diameter(mm)	wall thickness(mm)
Drill pipe	108.77	127.0	9.115
casing	220.51	244.4	11.95
Water riser	509.4	533.4	12

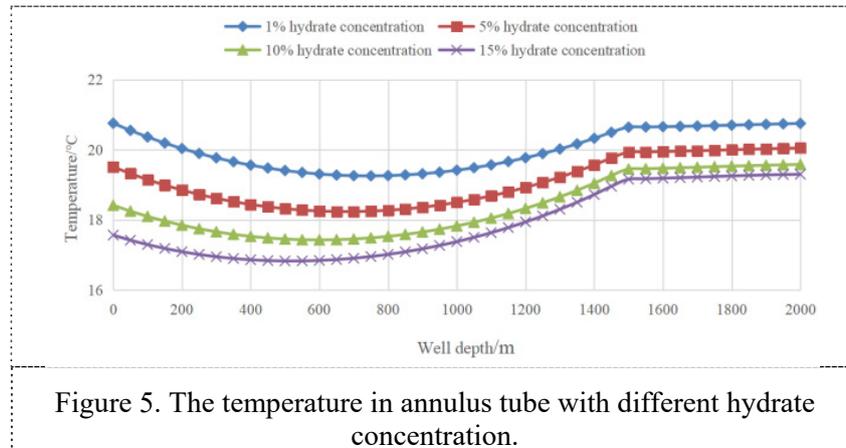
Cement ring outer diameter is taken as 132.2 mm. Cement ring thickness is 10 mm. Equivalent diameter of casing section and riser are 93.51 and 382.4 mm. The density of drilling fluid is 1200 kg/m³, the density of methane is 0.7174 kg/m³. The fluid static pressure at the bottom pressure is 40 MPa. And other basic parameters are shown in Table 4.

Table 4. Other basic thermodynamic parameters.

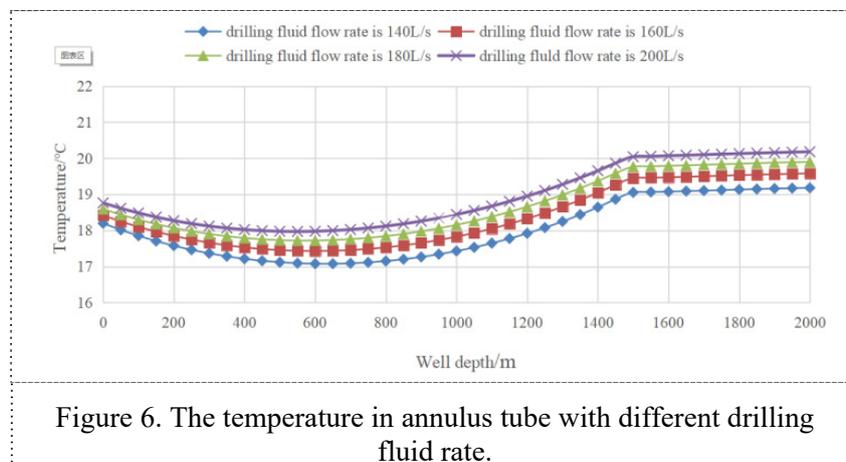
	number	unit
Specific heat capacity of drilling fluid	1670	J/(kg*K)
Kinetic viscosity of sea water	0.002	Pa*s
Thermal conductivity of methane	0.0302	w/(m*°C)
Thermal conductivity of drilling fluid	1.7	w/(m*°C)
NGH density	910	kg/m ³
Prandtl number of sea water	13.94	
Density of sea water	1020	kg/m ³
Formation density	2640	kg/m ³
Specific heat capacity of formation	837.36	J/(kg*K)
Thermal conductivity of formation	2.25	w/(m*°C)

4.2. The temperature distribution

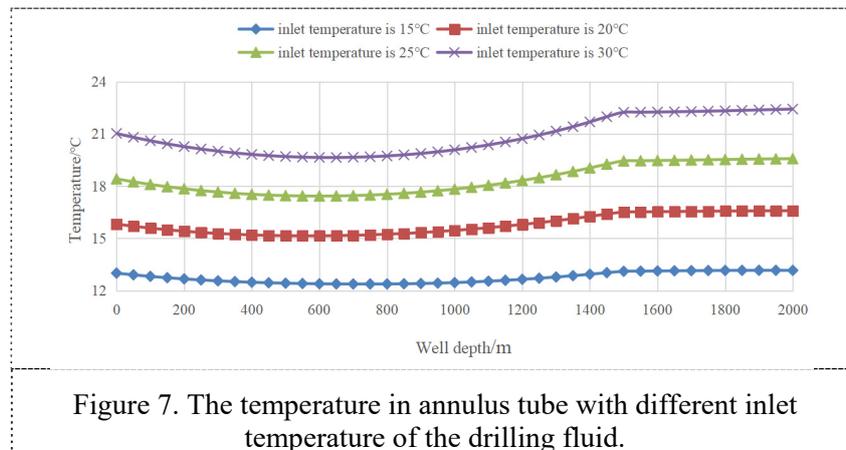
Through the formulas and inferences in the above sections, the temperature, pressure, and decomposition amount in annular tube can be calculated. In order to study the influence of different external factors on fluid temperature in annulus tube, the temperature in annulus tube under different hydrate concentration, volume flow rate of drilling fluid and inlet temperature of drilling fluid were simulated. Firstly, when the inlet temperature of drilling fluid is 25°C and the volume flow rate of drilling fluid is 160 L/s, the temperature in annulus with different hydrate concentration is obtained, as shown in figure 5. Under certain inlet flow of drilling fluid, the higher the volume concentration of the hydrate, the lower the temperature in annulus tube. Because when other conditions are certain, the greater the hydrate concentration, the more hydration decomposition along the process, and the decomposition of the hydrate is endothermic, so the decomposition of the hydrate will make the temperature in annulus tube lower.



When the hydrate concentration is 10% and the inlet temperature is 25°C, the flow rates of drilling fluids are 140L/s, 160L/s, 180L/s, 200L/s, respectively, the temperature inside the annulus is shown in figure 6. It can be seen from the figure that the larger the flow of drilling fluid, the higher the temperature in annulus tube. At a depth of 1500 m, there is a sudden change in temperature; from 1500 to 600 m, the temperature continues to decline; the inflection point appears at 600 m, and the temperature inside annulus tube changes from falling to rising. The drilling fluid flow rate is from high to low, and the temperature at the wellhead is 18.2°C, 18.4°C, 18.6°C, and 18.8°C, respectively. The temperature at the exits of different flow rate of drilling fluid does not change much.

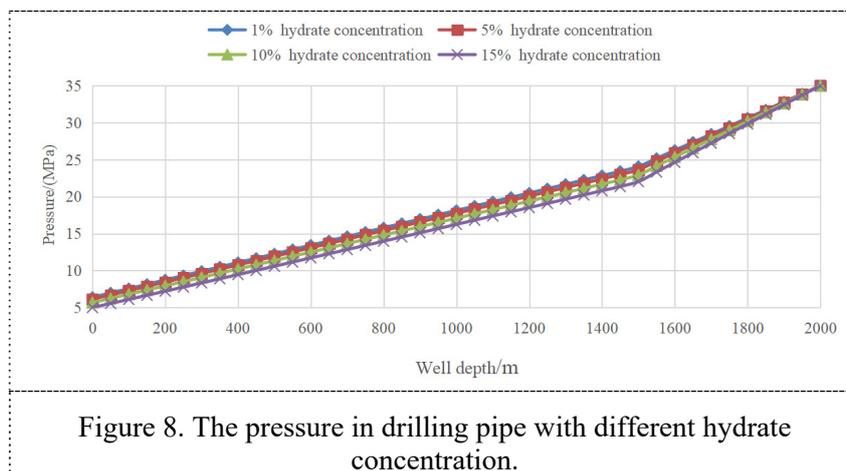


Under the condition that the hydrate concentration is 10% and the inlet flow rate of the drilling fluid is 160 L/s, the fluid temperature in annulus tube and drilling pipe with the inlet temperature of the drilling fluid is 15°C, 20°C, 25°C, and 30°C is calculated respectively. The results are shown in Figure 7. As can be seen from the above figure, the inlet temperature of the drilling fluid has a great influence on the temperature in the ring air pipe. The higher the inlet temperature of the drilling fluid, the higher the temperature in annulus tube.



4.3. The pressure distribution

Similarly, the distribution of pressure at different hydrate concentrations, drilling fluid flows and inlet temperatures is shown in figure 8-10. It can be seen from figure 8, the greater the concentration the lower the wellhead pressure. The outlet pressure of wellhead is 6.39MPa, 6.14MPa, 5.67MPa and 5.00MPa from small to large. The pressure loss is relatively large below the casing section (well depth below 1500m), and the pressure changes linearly in riser section and casing section. In the picture 9, the greater the flow rate of drilling fluid, the greater the pressure loss. And the influence of inlet temperature on annulus pressure is relatively small, as shown in figure 10. The lower the inlet temperature of the drilling fluid, the greater the pressure loss. When the inlet temperature of the drilling fluid is relatively high, the decomposition of the hydrate is more, and the more the hydrate is decomposed, the larger the amount of gas produced, the less the pressure loss will be.



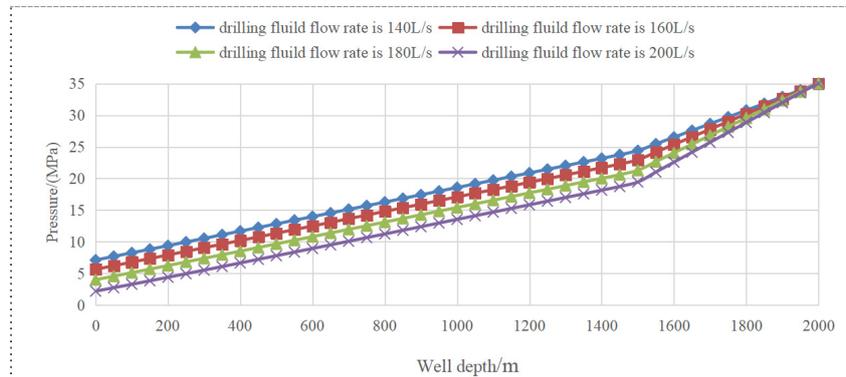


Figure 9. The pressure in drilling pipe with different drilling fluid rate.

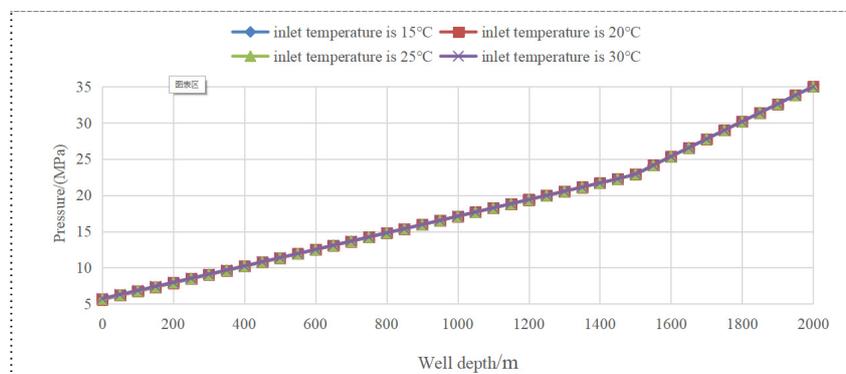


Figure 10. The pressure in drilling pipe with different inlet temperature of the drilling fluid.

5. Conclusion

In this paper, the temperature and pressure distribution in annulus tube and phase equilibrium pressure of hydrate in drilling fluid are calculated. The results show that under the same pressure, the lower the concentration of methane, the higher the temperature of hydrate formation, that is, the harder it is to decompose. However, most ions and alcohols in drilling fluid reduce the formation temperature of hydrate. By comparing the pressure and temperature in the annulus with the phase equilibrium pressure of hydrate, it can be seen intuitively that the whole annulus is in the state of hydrate decomposition except for the lower temperature of drilling fluid inlet. The larger the concentration of hydrate particles, the smaller the pressure difference, the slower the decomposition rate. Moreover, with the increase of drilling fluid flow rate, the difference between annulus pressure and phase equilibrium pressure is larger. So, when other conditions are consistent, increasing drilling fluid flow rate will cause the increase of gas hydrate decomposition rate. The inlet temperature of drilling fluid has a great influence on the decomposition zone of hydrate. When the inlet temperature is relatively low, it is in the stable state of hydrate at the bottom of well and above part of the area. If the amount of hydrate decomposition would be control, controlling the temperature of drilling fluid entry is a better measure. The disadvantage of the study is that the homogeneous model is used to calculate the solid-liquid-gas three-phase flow in annulus in one hand. In the other hand, in the process of calculating the temperature and pressure, the first-order discretization is adopted and the iteration step is longer. These problems will be improved in future research.

Acknowledgments

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