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ASSESSMENT OF HYDRATE FORMATION DEPTH IN THE OIL WELLS LOCATED IN PERMAFROST ZONES

ABSTRACT. The paper analyses the influence of oil movement speed on the process of gas hydrate formation in an oil well borehole in the conditions of intensive cooling by means of heat exchange with long-term permafrost soils as exemplified by the Paiyakhskoe field. The mathematical model of non-isothermal oil flow with dissolved gas in a vertical oil well borehole is considered. A simplifying assumption is temperature constancy of soils around the oil well. Analytical dependence of physical oil properties on pressure and temperature was used in numerical calculation of the oil flow parameters. The assessment of hydrate formation conditions was carried out by the VNIIGAZ method. The offered calculation methodology of P-T conditions in the oil well borehole is formulated as a numerical algorithm. The results of numerical calculations of pressure, temperature and hydrate formation depth are demonstrated by means of graphs. The analysis of the results of thermal and hydraulic calculations for oil flow in an oil well borehole allowed to define hydrate free oil production regimes and predictable depths of initial hydrate formation. It has been demonstrated that when a well bore passes through permafrost layers with a low speed of oil flow, favourable conditions for gas hydrate formation appear.

KEY WORDS. Hydrate formation, mathematical model, oil production.

Introduction

The development of most gas fields, gas condensate fields and a number of oil fields involves dealing with hydrate formation. This issue is of paramount importance in case of development of a field located in a long-term permafrost zone. High formation pressure and low temperatures create favourable conditions for hydrate formation in wells and pipelines.

Natural gas hydrates are an unstable physico-chemical compound of water and hydrocarbons which decomposes into gas and water at a higher temperature or lower pressure. In physical appearance, it is white crystalline mass resembling ice or snow. Formation of hydrates is possible both in gas and liquid phases, for example in oil-water emulsions with dissolved gas specific for oil wells [1, 2, 3].

Hydrates are substances in which molecules of some components are found in cavities between the nodes of associated molecules of another component. Such

compounds are usually called interstitial solutions or, sometimes, inclusion compounds. Molecules of hydrating agents are held in cavities between the nodes of associated molecules in a hydrate grid by means of van der Waals' forces.

1. Calculation of hydrate equilibrium curve

An insight into hydrate formation conditions is provided by a heterogeneous equilibrium phase diagram designed for the systems: hydrating agent—H_20, variables—pressure, temperature [1, 4]. The position of an equilibrium curve of hydrate formation temperature is determined by a hydrating agent's composition, water purity, flow turbulence, etc.

Gases CH_4, CO_2, H_2S, C_2H_6 form CS-I structure hydrates and gases Ar, C_3H_8, i-C_4H_{10} form CS-II structure hydrates.

According to the results of the chemical analysis of Paiyakhskoe oil field samples, the associated petroleum gas has the following composition:

Table 1

Composition of associated petroleum gas

Component	CH_4	C_2H_6	C_3H_8	$i-C_4H_{10}$	$n-C_4H_{10}$	C_5H_{12}	C_6H_{14}	C_7H_{16}	CO_2	N_2
Composition, total %	73.5	11.7	8.7	0.81	3.04	1.06	0.286	0.046	0.72	0.156

Hydrates with cubic structure-I will most often form in these conditions [1, 2, 3, 5]. Equilibrium conditions of hydrate formation in the system *natural gas—water—hydrate* were determined according to the method offered in [5] using the following algorithm:

Hydrate formation pressures are calculated for two predetermined temperatures (T_1 = 243,15 K and T_2 = 273,15 K) by means of solving the equation:

$$[1 + p(\sum_i a_i y_i)]^2 = \frac{1}{p\left[\sum_i \frac{y_i}{b_i}\right]} \quad (1)$$

where y_i — mole quantity of i component in a gas phase

a_i, b_i —temperature-dependent empirical parameters [5].

Equation (1) was solved using Newton's iteration method.

Equation parameters A and B of the hydrate equilibrium curve are determined. The curve is presented as follows:

$$\ln P = -\frac{A}{T} + B \quad (2)$$

Using equation (2), hydrate formation pressure at any temperature can be found. The error of the method does not exceed 1% for pressures below 12 MPa [5].

Using the algorithm above, a hydrate formation curve has been obtained for gas with the composition shown in Table 1.

2. Model dependencies of oil density and viscosity on pressure and temperature

To calculate the pressure and temperature distribution in an oil well borehole, it is necessary to take into account the dependence of physico-chemical properties of live oil on thermodynamic parameters. To simplify calculations, some dependencies were defined according to the results of laboratory-based analysis of deep oil samples and dissolved gas with a successive approximation by common correlation dependencies.

Oil density changes due to the oil degassing process at a lower pressure. The main parameters influencing this variable are a gas-oil ratio, a formation volume factor and bubble-point pressure [6]. The dependence of gas-oil ratio on the pressure has been approximated by the following function:

$$G = \begin{cases} G_0 - \frac{G_0}{p_s - p_{at}} \cdot (p_s - p), & p < p_s \\ G_0 & , p > p_s \end{cases} \quad (3)$$

where G is the instantaneous gas-oil ratio in m^3/m^3, $G_0 = 33{,}3\ м^3/м^3$ is its raw value at bubble-point pressure, p_s — bubble-point pressure. In its turn, bubble-point pressure was expressed as a linear function of temperature:

$$p_s = p_s(20°C) + K * (T - 293) \quad (4)$$

where $K = 0.022 \frac{1}{\text{MPa}}$; $p_s(20°C) = 5.2$ MPa.

The dependence of weakly compressible fluid density on the pressure was described as an exponential relationship [6]

$$\rho_f = \rho_0 \cdot e^{\beta(p - p_{at})} \cdot e^{BG} \quad (5)$$

where $\beta = 8.7 * 10^{-4} \frac{1}{\text{MPa}}$. and the volume factor, according to the results of laboratory-based studies, is $B = -2.3 * 10^{-3}\ m^3/m^3$.

The dependence of kinematic viscosity on the temperature was approximated by the following function [7]:

$$lg(lg(\nu + 0.7)) = A - B \cdot lg(T) \quad (6)$$

where coefficients A, B could be calculated using oil viscosity values ν found in laboratory-based research, at 20 °C and 50 °C.

$$\nu_{20} = 2.45 \frac{mm^2}{s}; \ \nu_{50} = 5.03 \frac{mm^2}{s}$$

The influence of dissolved gas on viscosity was estimated using Chew-Connally correlation [7]:

$$\mu = x \cdot (\nu(T) \cdot \rho_f)^y \quad (7)$$

where $x = 0.2 + 0.8 * 10^{(-0.00081 \cdot Rs)}$, $y = 0.43 + 0.57 * 10^{(-0.00072 \cdot Rs)}$

Rs is a gas-oil ratio in the American system of units *scf/stb*.

The assessment of the influence of pressure on viscosity at pressures higher than bubble-point pressure was based on Kahn et al correlation [9]:

$$\mu = \mu(p_s) * Exp(x) \quad (9)$$

where $x = 9.6 * 10^{-5} * (p - p_s) * 1.45 * 10^{-4}$.

The described approximations are shown in Fig. 1. The difference between the calculated data and laboratory values does not exceed 5%.

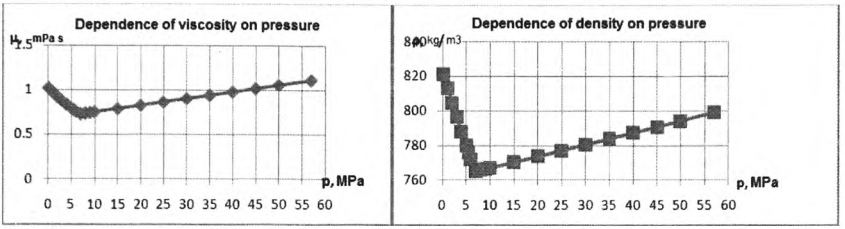

Fig. 1. Estimation of oil viscosity and density dependence on pressure at 91.5° C

3. Pressure and temperature calculation during oil flow in an oil well borehole.

In this section we shall formulate the problem of flowing well pressure calculation. There is an oil well penetrating an oil-bearing layer at the depth of 3400 m. The borehole radius is R = 0.1 m. The oil-well tubing diameter is D=0.07 m. During well flow regime the well production rate is controlled by a choke. According to the maintenance data, choke d = 3mm, bottom-hole pressure is 45.5 MPa, and the well production rate is 36 tonnes per day. The Dupuis formula for the given formation pressure P_r allows to determine production index of the well *PI* and establish linear dependence of the well production rate on bottom-hole pressure P_w:

$$q = PI * (P_r - P_w) \quad (10)$$

With the oil flow rate of 140-170 tn/day, pumping equipment should be used, as the bottom-hole pressure is not enough to lift fluid to the surface. In this case bottom-hole flow rate is specified by pump operation. After the bottom-hole level pump is turned on, the surface pressure should be between 0–0.05 MPa.

To calculate oil well pressures, hydraulic approximation is applied. Pressure drop down the borehole is determined by wall friction and a hydrostatic component [8, 9, 10]:

$$\frac{dp}{dz} = -F_w - \rho g,\ F_w = \frac{\lambda \rho_f v^2}{2g},\ \lambda \approx \frac{64}{Re}$$
$$q \approx \rho_f v \cdot \pi r^2 = const, \qquad \rho = \rho_f (1 - \alpha) + \rho_h \alpha \quad (11)$$

The expression for the flow friction characteristics corresponds to a laminar flow regime in an oil well borehole, which holds for low well production up to 40 tn/day. When well production is higher, the friction characteristics depend not only on

Reynolds number, but also on pipe roughness [9]. Well production of 50–70 tn/day falls into a laminar-turbulent transition zone. However, there is no analytical dependence for flow friction characteristics, and we have to estimate a possible value range using, for example, Moody diagrams analysis. Its value, calculated according to the formula of a laminar flow, is the lower boundary value both in critical and turbulent zones.

The initial conditions are as follows: bottom-hole temperature and pressure are $T_0 = 86°C$, $p_0 = 11.5 - 57.5$ MPa, $z_0 = 3400$ m. Calculation of pressure down the borehole was done numerically with the use of approximations of oil density and viscosity on pressure and temperature which were found earlier. The temperature was calculated using the equations below.

During the estimation of the oil well heat balance, it was assumed that convective heat transfer by oil in the borehole is compensated by the heat loss from the borehole into the surrounding rock. The heat loss into the surrounding rock mass was specified with regard to the well design (oil-well tubing and tubing annulus partially filled with gas) [9]:

$$\frac{dT}{dz} = \frac{2\pi\kappa \cdot q_t}{q \cdot c}, \; q_o = \frac{T - T_f}{\frac{1}{\alpha R} + \frac{1}{\lambda_g} \cdot \ln\left(\frac{R}{r}\right)} \qquad (12)$$

where $q_t = 2\pi R \cdot q_o$ — heat flow into the environment from 1m of tubing, $\alpha = 2\,\frac{W}{m^2}$ is average oil well/rock heat exchange coefficient, $\lambda_g = 0.03263\frac{W}{\ldots}$ — heat conduction of annular gas, c – average value of oil heat capacity $\approx 1900\frac{J}{kg \cdot K}$, T_f — surrounding rock temperature. The last value, which is below the long-term permafrost zone (z > 1000 m), is distributed in accordance with the linear geothermal law. In the permafrost zone (z < 1000 m) $T_f = 0°C$. Formation temperature $T_f(z = 3400) = T_f = 91.5$ °C.

The equation for heat balance was also calculated numerically. The example of joint solutions of hydrodynamic and heat problems is shown in Fig. 2.

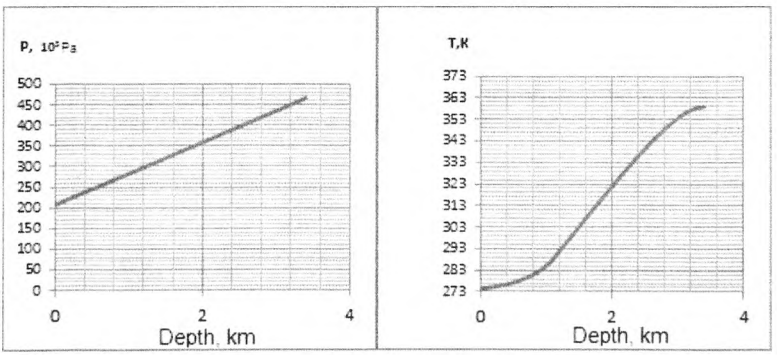

Fig. 2. Pressure and temperature distribution in an oil well borehole at the production of 30 tn/day

4. Calculation of hydrate formation depth

Using the estimation results of temperature and pressure distribution along the borehole, there were obtained phase curves demonstrating explicit dependence of pressure on temperature during different production regimes. In this case, plotting a phase diagram of hydrate formation and the given curves allows to clearly see the possible hydrate formation areas.

The calculation data are shown in Fig. 3. When the production rate is lower than 70 tn/day, conditions for hydrate formation appear. With high production rates, oil does not cool down to the hydrate formation temperature. Overlapping of borehole temperature and pressure distribution curves and the curve of hydrate formation allows to define the maximum depth of hydrate formation.

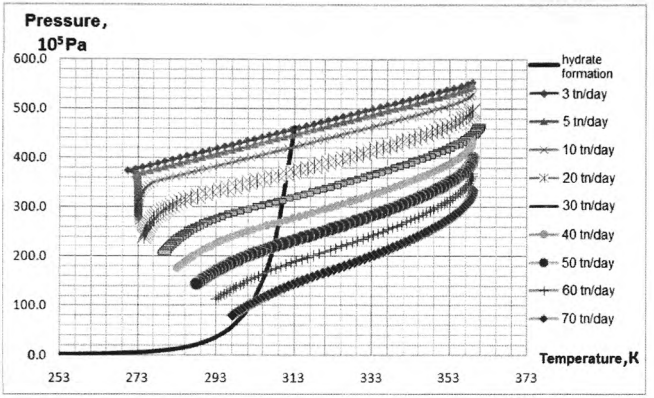

Fig. 3. Temperature and pressure distribution in an oil well borehole at different well production rates and a phase diagram of hydrate formation

As it can be seen in Fig. 3, in the upper sections of the well the conditions for hydrate formation are always fulfilled. The dependence of maximum possible hydrate formation depth on the well production rate is shown in Fig. 4.

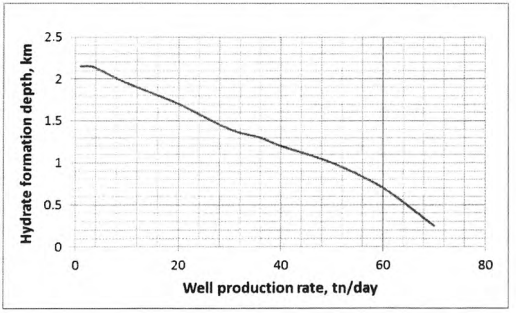

Fig. 4. The dependence of maximum hydrate formation depth on the well production rate

As it can be seen in Fig. 4, the starting point of hydrate formation can be located much lower than the base of the permafrost layer. Therefore, the deposition of hydrates is possible when the thickness of the permafrost is not great. The determining factors are the oil flow speed, the geothermal gradient and heat-conductivity factors.

Conclusion

The calculation methodology of P-T conditions in a borehole, offered in the paper, is based on analytical dependences of the oil flow properties and allows to calculate the depth of the hydrate formation starting point in an oil well borehole. It has been demonstrated that when a well bore passes through permafrost layers and well production rates are low, favourable conditions for gas hydrate formation appear. Conditions favourable for hydrate formation are maintained in the whole zone above the formation starting point.

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