

A Method and a Device for Determining the Temperature Variation of the Upward Reservoir Fluid Flow in the Tubing of the Oil Well

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Abstract: Using a comprehensive approach, a system analysis of studies in the field of heat transfer and temperature distribution along the length of oil production wells (along the height of the tubing) is given. A new method of determining the temperature of the upward reservoir fluid flow along the height of the tubing and a device for its implementation are proposed. It is shown that as the temperature decreases along the height of the tubing, the probability of asphaltene-resin-paraffin deposits (ARPD) increases, leading to complications in the operation of the oil production well (OPW); new mathematical models are proposed for determining the temperature distribution (TD) along the height of the tubing, taking into account the coefficients of heat transfer from the rising fluid flow to the inner wall of the tubing and from the outer wall of the tubing to the medium of the annulus (between the tubing and production casing (PC)), temperature gradient in the liquid and gas layer of the PC.

Keywords: Heat exchange, heat transfer, temperature distribution, algorithm, thermal conductivity, mathematical model

1. Introduction.

Numerous works are devoted to the issues of operating temperature of oil production wells (OPW), in which various aspects of this complex phenomenon are discussed [1-8]. As a result of analytical research on this issue, a significant number of solutions to the thermal conductivity equation describing temperature processes occurring during the movement of formation fluid along the OPW borehole were obtained.

Formation of asphaltene-resin-paraffin deposits (ARPD) on the surface of downhole equipment and the tubing is one of the main complications in OPW operation, which decreases the cross-sectional area of OPW casing and increases formation fluid flow viscosity and flow resistance. On the other hand, the thickness of the boundary layer increases, resulting in reduced heat loss. For successful ARPD prevention and removal measures, it is necessary to know the depth of the beginning of paraffinization of the wells [9,10].

Analysis of field data has shown that intensive ARPD formation occurs at fluid temperatures below the temperature of oil saturation with paraffin (paraffin crystallization) [2]. The process of paraffin adhesion takes place on the inner surfaces of the tubing and PC, which significantly decreases the coefficients of thermal conductivity (λ) and heat transfer (K) from the fluid flow to the medium, i.e., to the annulus. Therefore, it is necessary to determine the temperature distribution in the tubing with sufficient accuracy for practical purposes in order to detect ARPD formation points and develop technological measures for their removal or prevention of their formation.

Problem statement. In theoretical research of heat transfer through the cylindrical walls of the tubing to the annulus and in practical operation of oil reservoirs, OPW operation is accompanied by phase transitions related to the saturation of oil with ARPD components, deposition (adhesion) of these components on the inner surfaces of the tubing and uneven distribution of the composition and flow rate in the latter. In addition, along with heat conduction the process of heat exchange is also carried out by convective heat transfer; temperature variation along the OPW borehole is a synergism (joint action) of thermal processes occurring both in the oil reservoir, and in the tubing boreholes; at the same time, temperature distribution in vertical (upward) fluid flow from the bottomhole (perforation point) of the well to the suction valve of the tubing pump significantly differs from temperature distribution along the tubing height (from the suction valve of the tubing pump to its wellhead); in the first case heat transfer is intensive, because as heat transfer is between the upward fluid flow and the rock and the flow rate is much lower than in the tubing; and in the second case the heat transfer is between the upward fluid flow and the fluid and gas layer in PC. Consequently, development of mathematical models to estimate the temperature distribution along the height of the tubing, taking into account the above factors is a relevant problem and is the subject of this paper.

Solution. Taking into account the above-mentioned solutions to the problem, we have developed a method of determining the temperature

distribution of the upward flow along the length of the tubing and the schematic diagram of its implementation, which consists in measuring the temperature at the discharge line of the tubing and at the head of the production casing, the pressure at the discharge line at two points of the tubing of the well, one of which is located at the head of the tubing, and the second below it at a distance corresponding to half the length of the cylinder of the pump used, and the temperature distribution of the upward flow along the length of the tubing is calculated by the following algorithm:

$$t = t_0 + (t_i - t_0) \exp(-al)$$

$$a = \frac{\pi d_1 K}{G \rho C_f}$$

$$K = \frac{1}{\frac{1}{\alpha_1 D_1} + \frac{1}{2\lambda} \ln \frac{D_2}{D_1} + \frac{1}{\alpha_2 D_2}}$$

$$\lambda_f = \lambda_{f\beta} (1 + bt)$$

$$\alpha_1 = \frac{NU_f \lambda_f}{d_1}$$

$$NU_f = 0,021 Re_f^{0.8} \cdot Pr_f^{0.43}$$

$$Re_f = \frac{\omega_f d_1 \rho_f}{\mu_f}$$

$$Pr_f = \frac{\mu_f C_f}{\lambda_f}$$

$$\alpha_2 = \frac{NU_m \lambda_m}{(D_c - d_2)}$$

$$NU_m = 0,021 Re_m^{0.8} \cdot Pr_m^{0.43}$$

$$Re_m = \frac{\omega_m \rho_m (D_c - d_2)}{\mu_m}$$

$$Pr_m = \frac{\mu_m C_m}{\lambda_m}$$

$$G = \beta F \left(\frac{P_1 - P_2}{\rho_f} \right)^{0.5}$$

$$F = \frac{\pi d_0^2}{4}$$

$$\rho_f = \frac{\Delta P}{gh} = \frac{P_2 - P_1}{gh}$$

where d_1, l – diameter and length of the tubing, respectively, m;
 t, t_i – current and initial temperature of FF in the tubing, °C;
 t_0 – temperature of the medium (mainly gas) in the annulus, °C;
 K – heat transfer coefficient, kcal/(m²·°C·h);
 G – volumetric flow rate of FF, m³/h;
 C_f – heat capacity of FF, kcal/(kg·°C);
 ρ – density of FF, kg/m³;
 α_1 – heat transfer coefficient from fluid flow to the wall of the tubing, kcal/(m²·°C·h);
 h – distance between pressure sensors 1 and 2;
 α_2 – heat transfer coefficient from the wall of the tubing to the medium in the annulus, kcal/(m²·°C·h);
 D_1, D_2 – inner and outer diameters of the wall of PC, m;
 λ, λ_0 – current value and value under normal ($t = 0$) thermal conductivity conditions, kcal/(m²·°C·h);
 NU_f, NU_m – values of the Nusselt criterion for FF in the tubing and medium in the annulus, respectively, abstract (dimensionless) numbers;
 Re_f, Re_m – Reynolds number of fluid flow in the tubing and medium flow in the annulus, respectively, dimensionless numbers;
 β – hour-to-second conversion factor;
 Pr_f, Pr_m – values of the Prandtl criterion for FF in the tubing and the medium in the annulus, respectively, dimensionless numbers;

$\omega = \frac{4G}{\pi d_1^2}$ – velocity of WF FF in the tubing, m/h;
 μ_f, μ_m – dynamic viscosity coefficients of FF and medium in the annulus, respectively, mPa·S;
 C_m – heat capacity of the medium in the annulus, kcal/kg·°C;
 d_2 – outer diameter of the tubing, m;
 D_c – production casing diameter, m.

Fig.1. shows a schematic diagram of the device for implementing the method, where: 1 – sensor installed at the head of the tubing; 2 – sensor installed on the tubing below sensor 1, at a distance of half the height of the cylinder of the pump used, and a differential pressure gauge – 3; 4 – discharge line of the well; 5 – pressure sensor on the discharge line of the well and a differential pressure gauge – 6; 7 – liquid level sensor in the production casing and a transducer – 8; 9 – computation and indication unit; 10 – polished rod of the rod string; 11 – production casing string of the well; 12 – tubing; 13, 14 – temperature sensor and transducer on the discharge line of the tubing; 15, 16 – temperature sensor and transducer at the head of PC.

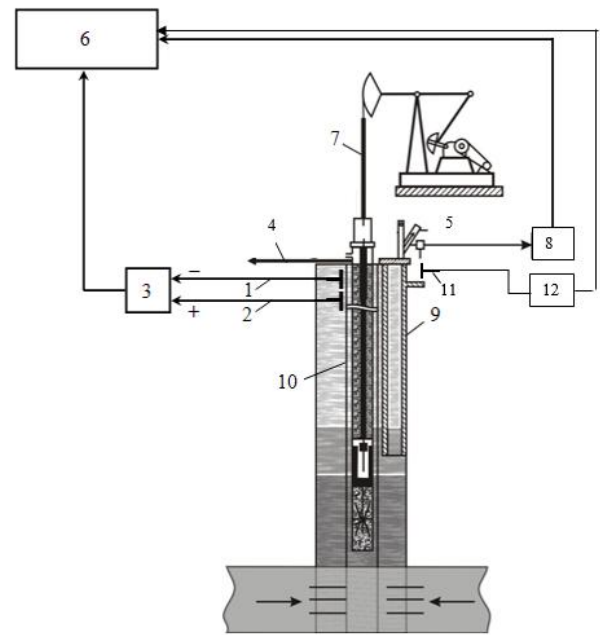


Fig.1. Schematic diagram of the device

The method is implemented as follows.

The differential pressure is measured between pressure sensors 1 and 2, installed at the head of the tubing at a distance of half the length l of the cylinder of the pump used at the given well: $h = 1/2 l$. Sensor 5 measures the pressure at discharge line 4 of the well. The outputs of the pressure sensors are connected to chambers 2–6 of the SAPFIR type differential pressure gauge, the outputs of which are connected to computation and control unit 9. And bottom sensor 2 is connected to the positive chamber of differential pressure gauge 3, and the upper one 1 is connected to the negative chamber of differential pressure gauge 3 and the positive chamber of differential pressure gauge 6. The outputs of sensor 5 are connected to the respective chambers of differential pressure gauge 6. Temperatures are measured at points 13 and 15, the outputs of which are connected to unit 9 via transducers 14 and 16.

Water and oil densities (ρ_w, ρ_o) and the amount of water in the fluid in fractions (α) are determined in laboratory. Since the characteristics of the reservoir being developed are quite stable, lab measurements are performed no more frequently than once a month.

Example:

$$\rho_o = 860 \frac{\text{kg}}{\text{m}^3}; \quad \rho_w = 1100 \frac{\text{kg}}{\text{m}^3}; \quad \text{water cut of FF } W = 0.8$$

$$\rho_r = 2 \cdot 10^{-3} \frac{\text{kg}}{\text{m}^3}; \quad d_1 = 6.10^{-2} \text{ m}; \quad D_2 = 1.68 \text{ m}; \quad G_c = 1.25 \frac{\text{m}^3}{\text{h}};$$

$$C_c = 0.96 \frac{\text{kcal}}{(\text{kg} \cdot ^\circ\text{C})}; \quad 4 \text{ mPa} \cdot \text{C}; \quad \mu_c = 6.59 \cdot 10^{-3} \text{ mPa} \cdot \text{C};$$

$$\mu_r = 40 \cdot 10^{-3} \text{ mPa} \cdot \text{C}; \quad \lambda_c = 0.566 \frac{\text{kcal}}{(\text{m} \cdot ^\circ\text{C} \cdot \text{h})}; \quad \lambda_r$$

$$= 2.1 \cdot 10^{-2} \frac{\text{kcal}}{(\text{m} \cdot ^\circ\text{C} \cdot \text{h})};$$

$$t_0 = 25^\circ\text{C}; \quad t_o = 40^\circ\text{C};$$

$$\omega_c = \frac{G_c \cdot 4}{\pi d_1^2 \cdot 3600} = \frac{1.25 \cdot 4}{3.14(0.06)^2 \cdot 3600} = 0.122 \text{ m/c}$$

$$\omega_r = \frac{G_r \cdot 4}{\pi (D_3 - d_1)^2 \cdot 3600} = \frac{6.03 \cdot 4}{3.14(0.168 - 0.06)^2 \cdot 3600} = 0.11844$$

$$Re_c = \frac{\omega_c \cdot d_1 \cdot \rho_c}{\mu_c} = \frac{0.122 \cdot 0.06 \cdot 1052}{0.659 \cdot 10^2} = 1169$$

$$Re_r = \frac{\omega_r \cdot (D_3 - d_2) \cdot \rho_r}{\mu_r} = \frac{0.1844 \cdot (1.68 - 0.062) \cdot 2 \cdot 10^{-3}}{0.659 \cdot 10^2} = 997.32$$

$$Pr_c = \frac{\mu_c C_c}{\lambda_c} = \frac{40 \cdot 10^{-3} \cdot 0.96}{0.566} = 2.51$$

$$Pr_r = \frac{\mu_r C_r}{\lambda_r} = \frac{40 \cdot 10^{-3} \cdot 0.24}{0.021} = 0.4577$$

$$Pr_c^{0.43} = 1.4918$$

$$Pr_r^{0.8} = 0.717$$

$$Pe_c^{0.8} = 288.7$$

$$Pe_r^{0.8} = 252.1$$

$$Nu_c = 0.021 \cdot Pe_c^{0.8} Pr_c^{0.43} = 0.021 \cdot 288.7 \cdot 1.4918 = 9.03$$

$$\alpha_1 = Nu_c \cdot \frac{\lambda_c}{d_1} = 9.03 \cdot \frac{0.566}{0.06} = 85.18$$

$$Nu_r = 0.021 \cdot Pe_r^{0.8} Pr_r^{0.43} = 0.021 \cdot 252.1 \cdot 0.717 = 3.796$$

$$\alpha_2 = Nu_r \cdot \frac{\lambda_r}{D_3 - d_2} = 3.796 \cdot \frac{0.21}{0.0106} = 53.1$$

$$K = \frac{1}{\frac{1}{\alpha_1 d_1} + \frac{1}{2\lambda_{cr}} \ln \frac{d_2}{d_1} + \frac{1}{\alpha_2 d_2}} = \frac{1}{\frac{1}{85.18 \cdot 0.06} + \frac{1}{53.1 \cdot 0.064}} = 2.058$$

$$a = \frac{\pi d_1 K}{G_c \rho_c C_c} = \frac{3.14 \cdot 0.06 \cdot 2.058}{1.25 \cdot 1052 \cdot 0.96} = 4.44 \cdot 10^{-5}$$

$$al = 4.44 \cdot 10^{-5} \cdot 1.2 \cdot 10^3 = 0.38$$

$$t = t_0 + (t_o - t_0) \exp(-al) = 25 + (40 - 25) \exp(-0.38) = 25 + 15 \cdot 0.683 = 35.25$$

The technical effect of this study is the accuracy of the measurement, and the calculation algorithm makes it possible to correctly determine the temperature distribution of the upward flow of reservoir fluid in the tubing.

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