

## TEMPERATURE DISTRIBUTION IN OIL- AND WATER-SATURATED RESERVIOR WITH ACCOUNT OF OIL DEGASSING<sup>1</sup>

A.Sh. Ramazanov, A.V. Parshin

The monitoring of oil extraction to streamline oil field development is effected through a complex of geophysical techniques. The most informative and widely-used of them is **borehole thermometry** which is used to identify the operational zones in the well, to determine oil and water flows (watered formations) into the well and to assess the technical condition of the well both during the established and non-established modes of the well operation [1, 2 et al.]. First temperature measurements were performed in the beginning of the twentieth century by professor D.V. Golubyatnikov. In the field of the theory of temperature distributions during fluid filtration in porous media with account of thermodynamical effects first investigations were carried out in the beginning of the fortieth century by B.B. Lapuk.

Theoretical basics of the thermometry and theoretical substantiation of the thermodynamical methods of formation evaluation were developed, basically, for the case of single-phase fluid filtration in reservoir. For real processes of the filtration in petroleum reservoirs the more adequate being model of multi-phase non-isothermal oil, water and gas filtration. Fluid filtration in reservoir is followed by temperature change not only because of barothermal effect, but also by heat of phase transition during fluid degassing. In most cases oil recovery is concerned with multi-phase flows. Multi-phase filtration in a reservoir with phase transitions occurs during reservoir study when bubble-point pressure is close to formation pressure as well as during completion and formation test with reduction of bottom-hole pressure below bubble-point pressure.

Analysis of borehole data shows that previously developed methods of investigation and interpretation of thermodynamical data for single-phase flows during oil degassing are not sufficient enough.

That is why **one of the issues of current importance** for borehole geophysics is exploitation of the theory of thermodynamical distributions during multi-phase fluid filtration in reservoirs. They are described with the system of non-linear differential equations which is fairly difficult to solve [3].

This work represents investigation of an analytical model which describes formation of the temperature distribution in the reservoir with combined formation water and gas-cut oil inflow to the well.

**Problem statement.** Initially the reservoir is saturated by the gas-cut oil and water. At the moment  $t=0$  bottom-hole pressure is decreased to the value  $P_w$ , which is lower than the pressure of oil saturation by gas  $P_s$ , and then it is maintained as constant. Pressure is equal to the initial value  $P_r$  on the external boundary of the reservoir  $R_e$ . Reservoir saturation by water and oil on the external boundary of the reservoir is also maintained equal to their initial values in the reservoir. There is no inflow of free gas thorough the external boundary. Gas phase starts to separate from the distance  $r_s$  where pressure decreases below the saturation pressure. An analytical solution which describes temperature changes on the wellbore wall in time is to be obtained.

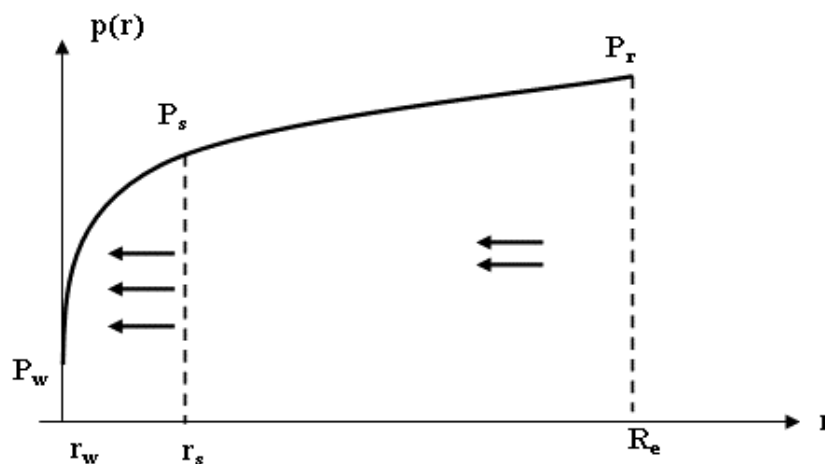
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**Assumptions taken.** The main assumption is that steady regime of the filtration establishes instantly in the reservoir (therefore flow rates and saturations) after pressure decrease in the wellbore below the saturation pressure. The model was first used by E.B. Chekaluk to estimate temperature distribution during single-phase filtration of weakly-compressed fluids [4]. The method allows to divide thermogydrodynamical problem into hydrodynamical and thermal. At the same time for pressure and saturation distributions, and phase flow rate in reservoir steady-state solutions in isothermal approximation are taken. Using these distributions a separate problem about temperature change is solved. The method is known to be applied for the estimation of temperature distributions and during gas-cut oil filtration in porous reservoirs [5].

The rest assumptions taken in the model:

- porous reservoir, homogeneous and horizontal;
- natural temperature  $T_{res}$  along the reservoir is constant;
- formation is exposed by perfect wellbore with radius  $r_w$ ;
- constant formation pressure  $P_r$  on external boundary  $R_e$  is maintained above saturation pressure  $P_s$ ;
- one-temperature model, temperatures of all phases and of the skeleton of the porous medium in each point of the reservoir are equal;
- adiabatic approximation, influence of the heat transfer to the bottom and capping rocks on the reservoir temperature distribution is neglected;
- radial heat conductivity in the reservoir is neglected due to convective heat transfer;
- degassing from reservoir water is neglected;
- within  $p > P_s$  oil and water temperature change due to throttling effect;
- for  $p < P_s$  throttling effect in oil, water and free gas as well as heat of oil degassing are taken into account;
- barotropic approximation, influence of temperature change in the reservoir on the parameters of fluid and reservoir is neglected.

**Pressure distribution.** Pressure distribution in the reservoir establishes instantly according to the accepted assumptions above. That leads to three-phase water, oil and gas filtration and evolution of dissolved gas within zone  $[r_w, r_s]$ . Two-phase filtration of water and gas-cut oil is takes place beyond this zone in the region  $[r_s, R_e]$ .



**Fig. 1.** Problem statement.

Using the Christianovich's model for the description of steady-state filtration we consider that oil degassing changes the reservoir permeability in the zone  $[r_w, r_s]$  from  $k$  to  $Ak$ , where

$$A \approx 0.944 - 21.43 \frac{\alpha P_0 \mu_2}{\mu_1}.$$

Here  $\alpha$  – gas solubility coefficient,  $\text{m}^3/\text{m}^3\text{Pa}$ ;  $P_0$  – normal pressure, Pa;  $\mu$  – dynamic viscosity, Pa\*s. Index 1 is referred to the oil, 2- to the gas.

Then the reservoir pressure distribution describes in the following way

$$p(r) = \begin{cases} P_w + \frac{\Delta P}{W} \ln\left(\frac{r}{r_w}\right); & r_w \leq r \leq r_s \\ P_r - \frac{A\Delta P}{W} \ln\left(\frac{R_e}{r}\right); & r_s < r \leq R_e \end{cases} \quad (1)$$

Here

$$W = \ln\left(\frac{r_s}{r_w}\right) + A \ln\left(\frac{R_e}{r_s}\right),$$

$\Delta P = P_e - P_w$  - total pressure drop in the reservoir;

The distance to initial liberation boundary of gas  $r_s$  is defined from the expression

$$\ln\left(\frac{r_s}{r_w}\right) = \frac{A}{A+n} \ln\left(\frac{R_e}{r_w}\right), \quad n = \frac{\Delta P_2}{\Delta P_1}. \quad (2)$$

$\Delta P_1 = P_s - P_w$  - pressure drop in the degassing zone;

$\Delta P_2 = P_r - P_s$  - pressure drop beyond the degassing zone, in the region of the one-phase filtration;

Filtration rate of oil for all  $r$  is described by the formula

$$v(r) = -\frac{v_0}{r}; \quad v_0 = \frac{Akk_1(s) \Delta P}{\mu_1 W}. \quad (3)$$

**Solution of the temperature problem.** Temperature change beyond the degassing zone (for  $r > r_s$  and  $p > P_s$ ) during the filtration of the water-oil mixture can be obtained solving the problem

$$C(s) \frac{\partial T}{\partial t} + (c_1 \rho_1 v_1 + c_3 \rho_3 v_3) \frac{\partial T}{\partial r} + (c_1 \rho_1 v_1 \varepsilon_1 + c_3 \rho_3 v_3 \varepsilon_3) \frac{dp}{dr} = 0, \quad r_s < r < R_e, \quad t > 0 \quad (4)$$

$$T|_{t=0} = 0; \quad T|_{r=R_e} = 0; \quad (5)$$

Here  $C(s)$  – volume heat capacity of the porous medium saturated by the oil and water,  $\text{J/m}^3\text{K}$ ;  $c_i$  – specific heat capacity,  $\text{J/kgK}$ ;  $\rho_i$  – density,  $\text{kg/m}^3$ ;  $v_i(r)$  – filtration rate,  $\text{m/s}$ ;  $\varepsilon$  – Joule-Thomson coefficient,  $\text{K/Pa}$ . The lower index 1 is referred to the oil and 3 – to the water.

Using mass conservation equations of oil and water we get

$$r\rho_1v_1 = R_e\rho_1^e v_1^e, \quad r\rho_3v_3 = R_e\rho_3^e v_3^e,$$

where upper index  $e$  is pointed to the value of the parameters on  $r = R_e$ .

Then instead of (4) after easy transformations we receive

$$\frac{\partial T}{\partial t} - \frac{u_{13}}{r} \left[ \frac{\partial T}{\partial r} + \varepsilon_{13} \frac{dp}{dr} \right] = 0, \quad r_s < r < R_e, \quad t > 0 \quad (6)$$

Here

$$u_{13} = \frac{c_1 + c_3 \cdot WOR}{C(s)} \rho_1^e |v_1^e| R_e;$$

$$\varepsilon_{13} = \frac{c_1\varepsilon_1 + c_3\varepsilon_3 \cdot WOR}{c_1 + c_3 \cdot WOR} - \text{Joule-Thomson coefficient of oil-water mixture;}$$

$$WOR = \frac{\rho_3^e v_3^e}{\rho_1^e v_1^e} - \text{mass flow rates ratio of water and oil.}$$

The solution of (6) for  $r=r_s$  under the conditions (5) is given by

$$T(r_s, t) = \begin{cases} \varepsilon_{13} \cdot \left[ p(\sqrt{r_s^2 + 2u_{13}t}) - P_s \right] & t \leq t_2 \\ \varepsilon_{13} \cdot (P_r - P_s), & t > t_2 \end{cases} \quad (7)$$

$$t_2 = \frac{R_e^2 - r_s^2}{2u_{13}} - \text{stabilization time of the throttle thermal distribution on } r=r_s.$$

We use the following equation of the heat flow during the three-phase filtration with the phase transfer from [6] for the calculation of the temperature distribution in the oil degassing zone for  $p < P_s$

$$C(s) \frac{\partial T}{\partial t} + \sum_{i=1}^3 c_i \rho_i v_i \frac{\partial T}{\partial r} + \sum_{i=1}^3 c_i \rho_i v_i \varepsilon_i \frac{dp}{dr} + Jq = 0, \quad r_w < r < r_s, \quad t > 0 \quad (8)$$

$$T|_{t=0} = 0; \quad T|_{r=r_s} = T(r_s, t); \quad (9)$$

Here  $C(s)$  – heat capacity of reservoir volume unit saturated with oil, water and gas,  $\text{J/m}^3\text{K}$ ;  $q$  – specific degassing heat,  $\text{J/kg}$ ;  $J$  – mass oil degassing rate on the unit of the reservoir volume,  $\text{kg/m}^3\text{s}$ . Index  $i = 1$  is referred to the oil, 2 – gas, 3 – water.

Temperature change according to (8) results from:

- convective heat transfer by phases;
- throttling during filtration of water and gas phases;
- degassing heat of oil.

Further, we express mass rate of phases in the degassing zone by means of mass rate of oil on  $r = r_s$ .

$$\rho_3 v_3 = \frac{r_s}{r} \rho_{3s} v_{3s} = \frac{r_s}{r} \rho_{1s} v_{1s} \cdot WOR, \quad (10)$$

$$\rho_2 v_2 = \frac{r_s}{r} \frac{g_s - g}{1 - g} \rho_{1s} v_{1s} \quad (11)$$

$$\rho_1 v_1 = \frac{r_s}{r} \frac{1 - g_s}{1 - g} \rho_{1s} v_{1s} \quad (12)$$

We also express an intensity of oil degassing  $J$  by means of the oil mass rate

$$J = -\frac{r_s \rho_{1s} v_{1s}}{r} \frac{1 - g_s}{(1 - g)^2} \cdot \frac{dg}{dr}, \quad (13)$$

$g(r)$  - mass concentration of dissolved gas in oil.

Equation for the temperature after substitution (10) – (13) to (8) has the following view

$$\frac{\partial T}{\partial t} - \frac{u_1(r)}{r} \left[ \frac{\partial T}{\partial r} + \varepsilon^*(r) \frac{dp}{dr} \right] = 0, \quad r_w < r < r_s, \quad t > 0 \quad (14)$$

which is to be solved under the edge conditions

$$T|_{t=0} = \varphi(r); \quad T|_{r=r_s} = T(r_s, t); \quad (15)$$

Here  $T(r_s, t)$  is the known temperature change on the boundary where starts oil degassing, and it is described by the formula (7).

$$u_1 = \frac{c_1(1 - g_s) + c_2(g_s - g) + c_3(1 - g) \cdot WOR}{(1 - g)C(s)} \rho_1^e |v_1^e| R_e; \quad (16)$$

$$\varepsilon^* = \frac{c_1 \varepsilon_1(1 - g_s) + c_2 \varepsilon_2(g_s - g) + c_3 \varepsilon_3(1 - g) \cdot WOR - q \frac{dg}{dp} \frac{1 - g_s}{1 - g}}{c_1(1 - g_s) + c_2(g_s - g) + c_3(1 - g) \cdot WOR} \quad (17)$$

$\varepsilon^*$  - effective throttle coefficient of the gas-liquid mixture, taking into consideration oil degassing heat.

In (16) it is considered that the mass flow rate of oil on  $r=r_s$  is equal to the mass flow rate of oil on external boundary  $r=R_e$ , i.e.

$$\rho_1^s v_1^s r_s = \rho_1^e v_1^e R_e$$

Initial temperature distribution  $\varphi(r)$  takes into account changes of reservoir temperature as a result of instant decrease of the pressure from  $P_r$  to  $p(r)$ . Neglecting adiabatic effect, temperature changes in the reservoir due to the “first portion” of the separated gas, granting instant heat exchange between skeleton and porous medium, could be written in the following form

$$\varphi(r) = -\frac{m\rho_1 s_1 q}{C(s)} [g_s - g(r)] \quad (18)$$

The problem (14) – (15) under definite approximations is easily solved with method of characteristics. An approximate solution of the problem is considered below. Feasibility of practical use of the solutions obtained in this approach is defined by low mass concentration of dissolved gas in oil.

#### Approximate solution. Method of calculation.

1) Change of the volume heat capacity of porous medium as a result of appearing of the gas phase is neglected. Let  $C(s) = const$ .

$$C(s) = ms_1 c_1 \rho_1 + ms_3 c_3 \rho_3 + (1-m)c_{sc} \rho_{sc},$$

and the constant values of saturations are taken from the external boundary of the region during calculations, i.e.  $s_i = s_i^e$ .

2) Gas dissolves in oil according to the Henry's law

$$g(p) = \alpha \bar{p} p; \quad \bar{p} = \frac{\rho_2^0}{\rho_1^0}$$

3) Water-oil factor is defined by the ratio of water and oil mobilities on the external boundary of the reservoir

$$WOR = \frac{k_3(s^e) \cdot \mu_1}{k_1(s^e) \cdot \mu_3}$$

4) Water and oil are incompressible, density change of the oil phase as a result of the degassing is also neglected.

5) Filtration rate of the oil on the external boundary is calculated according to (1) using the formula

$$|v_1^e|_{R_e} = \frac{kk_1(s^e) A \Delta P}{\mu_1 W}$$

Values  $g, \varepsilon_2$  in (16), (17) are variable in the region  $[r_w, r_s]$ . Let us consider two cases of integrating of the equation (14) with the constant values of these parameters.

**1<sup>0</sup>**. Taking in (16) and (17)  $g = g_s$ ,  $\varepsilon_2 = \varepsilon_2(P_s) = const$ , we receive

$$u_1 = \frac{c_1 + c_3 \cdot WOR}{C(s)} \rho_1^e |v_1^e| R_e; \quad (19)$$

$$\varepsilon^* = \frac{c_1 \varepsilon_1 + c_3 \varepsilon_3 \cdot WOR - \frac{q \alpha \bar{\rho}}{1 - g_s}}{c_1 + c_3 \cdot WOR} \quad (20)$$

As we can see  $u_1$  and  $\varepsilon^*$  are constant now.

In this approximation convective heat transfer by free gas and cooling as a result of the gas throttling are neglected. Obviously, that with the small mass flow rates of the gas doesn't result in big distortion of the temperature distribution.

**2<sup>0</sup>**. In the second case we shall take maximum values of the variable magnitudes  $\varepsilon$  and  $g$  on the wellbore wall  $r = r_w$ , i.e. letting in (16) and (17)  $g = g_w = const$ ,  $\varepsilon_2 = \varepsilon_2(P_w) = const$ . Then

$$u_1 = \frac{c_1(1 - g_s) + c_2(g_s - g_w) + c_3(1 - g_w) \cdot WOR}{(1 - g_w)C(s)} \rho_1^e |v_1^e| R_e; \quad (21)$$

$$\varepsilon^* = \frac{c_1 \varepsilon_1(1 - g_s) + c_2 \varepsilon_2(g_s - g_w) + c_3 \varepsilon_3(1 - g_w) \cdot WOR - q \alpha \bar{\rho} \frac{1 - g_s}{1 - g_w}}{c_1(1 - g_s) + c_2(g_s - g_w) + c_3(1 - g_w) \cdot WOR} \quad (22)$$

Solution of the equation (14) under the edge conditions (15) for the constant  $u_1$  and  $\varepsilon^*$  has the view

$$T(r_w, t) = \begin{cases} \varepsilon^* \cdot [p(\sqrt{r_w^2 + 2u_1 t}) - P_w] + \varphi(\sqrt{r_w^2 + 2u_1 t}), & t \leq t_1 \\ \varepsilon^* \cdot (P_s - P_w) + \varepsilon_{13} \cdot [p(\sqrt{r_s^2 + 2u_{13}(t - t_1)}) - P_s], & t_1 < t < t_1 + t_2 \\ \varepsilon^* \cdot (P_s - P_w) + \varepsilon_{13} \cdot (P_r - P_s), & t_1 + t_2 < t \end{cases} \quad (23)$$

Here

$$t_1 = \frac{r_s^2 - r_w^2}{2u_1}.$$

Radius of the hot probing reaches the boundary of the beginning of degassing during the time  $t_1$ , and during the time  $t_1 + t_2$  – external boundary of the reservoir  $R_e$ .

Basically, the solution (23) is true for any given function  $p(r)$ , which describes the steady-state pressure distribution in the reservoir during the filtration of gas-cut oil

and water. Further, with provision for (1) and (8), solution of (23) has the following view

$$T(r_w, t) = \begin{cases} \frac{\varepsilon^* \Delta P_1}{2 \ln\left(\frac{r_s}{r_w}\right)} \ln\left(1 + \frac{2u_1 t}{r_w^2}\right) - \frac{ms_1^e q \rho_2^0 \Delta P_1}{C(s)} \left[ 1 - \frac{\ln(1 + 2u_1 t / r_w^2)}{2 \ln(r_s / r_w)} \right]; & t \leq t_1 \\ \varepsilon^* \Delta P_1 + \frac{\varepsilon_{13} \Delta P_2}{2 \ln\left(\frac{R_e}{r_s}\right)} \ln\left(1 + \frac{2u_{13}(t - t_1)}{r_s^2}\right), & t_1 < t < t_1 + t_2 \\ \varepsilon^* \Delta P_1 + \varepsilon_{13} \Delta P_2, & t_1 + t_2 < t \end{cases} \quad (24)$$

where

$$u_1 = \frac{c_1(1 - g_s) + c_2(g_s - g) + c_3(1 - g) \cdot WOR}{(1 - g)C(s)} \rho_1^e |v_1^e| R_e,$$

$$\varepsilon^* = \frac{c_1 \varepsilon_1(1 - g_s) + c_2 \varepsilon_2(g_s - g) + c_3 \varepsilon_3(1 - g) \cdot WOR - q \frac{dg}{dp} \frac{1 - g_s}{1 - g}}{c_1(1 - g_s) + c_2(g_s - g) + c_3(1 - g) \cdot WOR} - \text{effective}$$

throttling coefficient of oil-water mixture which takes into account the heat of oil degassing.

**Analysis of the solution.** We can do the following obvious conclusions based on the formula (24):

1. After abrupt decrease of the pressure from  $P_r$  to  $P_w$  (below the saturation pressure) according to our model an instant decrease of the temperature in the reservoir in the whole degassing zone takes place. Maximum temperature decrease is naturally observed on the wellbore wall. It is equal to

$$\Delta T_0 = -k_{\text{deg}} \cdot \Delta P_1 \quad (25)$$

where

$$k_{\text{deg}} = \frac{ms_1^0 \alpha \rho_2^0 q}{C(s)}.$$

For  $m=0.2$ ,  $s_1^0=1$ ,  $\rho_2^0=0.8 \text{ kg/m}^3$ ,  $q=160 \text{ kJ/kg}$ ,  $C(s)=5 \text{ MJ/m}^3\text{K}$ ,  $\alpha=2 \text{ atm}^{-1}$  we get  $k_{\text{deg}} \approx 0.01 \text{ K/atm}$ . Thus under  $\Delta P_1 = 20 \text{ atm}$  the initial temperature drop as a result of the oil degassing is approximately  $-0.2 \text{ K}$ .



Initial temperature decline in the reservoir on the wellbore wall as a result of the adiabatic effect in the oil is

$$\Delta T_0 = -k_{ad} \cdot \Delta P_1 \quad (26)$$

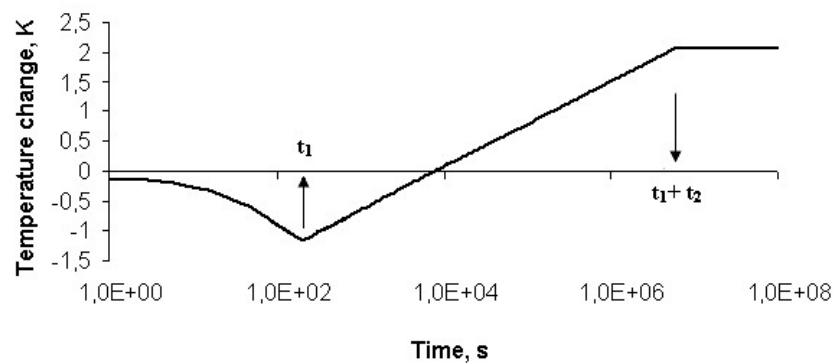
where

$$k_{ad} = \frac{ms_1^0 c_1 \rho_1 \eta_1}{C(s)}.$$

Under  $m=0.2$ ,  $s_1^0=1$ ,  $c_1 \rho_1 = 1.6 \text{ MJ/m}^3\text{K}$ ,  $\eta = 0.014 \text{ K/atm}$ ,  $C(s)=5 \text{ MJ/m}^3\text{K}$  we receive  $k_{ad} \approx 0.001 \text{ K/atm}$ , which is on the order less than temperature decreasing as a result of the separating of the “first portions” of the gas. It indicates on the admissibility of ignoring the adiabatic effect in our problem. The model can be improved for the taking into consideration the adiabatic effect when needed.

2. There are three specific stages in temperature change with time.

In fig. 2 one of the calculated curves of temperature change with time of the influent gas-liquid mixture is shown.



**Fig. 2.** Behavior of the bottom-hole temperature change with time.

In the early stages the temperature either increase or decrease according to the sign of  $\varepsilon^*$ . In fig. 2 temperature drop is observed. It is stimulated by the heat capacity of the skeleton of porous medium and heat capacity of the saturating fluids. The maximum value of the negative temperature anomaly takes out with time. The duration of the first stage is determined by the size of the degassing zone and by the rate of the convective heat transfer (which is mainly determined by the specific flow rates of water and oil).

The second stage goes on within the time  $t_2$  and completes by the full stabilization of the temperature distribution in the reservoir. It depends on the rate of the convective heat transfer, radius of the degassing zone and external radius of the cone of depression.

2. Under  $\varepsilon^* > 0$  temperature on all stages increases, stable-state temperature anomaly also positive. This case is typical for the small gas-oil ratios.

3. Under  $\varepsilon^* = 0$  temperature of the incoming from the reservoir mixture during the time  $t_1$  changes only due to the carrying-out from the reservoir the initial tempera-

ture distribution, made by the “first portion” of the selected gas. Value of the temperature anomaly in the wellbore is small in that case, and it is less than  $\Delta T_0$  by the absolute value and is defined from the formula (25). The degassing heat compensates throttle heating of the oil in the degassing zone in that case.

For the times  $t > t_l$  temperature anomaly becomes positive and increases with the time. Stable temperature anomaly is positive in point of time  $t_l + t_2$  and equals to  $\varepsilon_{13} \Delta P_2$ .

The value of the gas dissolubility coefficient of oil for which such situation of the temperature change is possible can be estimated from the equation

$$\alpha_{inv}^1 \approx \frac{\varepsilon_1 c_1}{q \bar{\rho}} + WOR \cdot \frac{\varepsilon_3 c_3}{q \bar{\rho}}. \quad (27)$$

As long as  $\varepsilon_1 c_1 \approx \varepsilon_3 c_3$ , then inverse dissolubility for the watered reservoir approximately in  $(1+WOR)$  times exceeds the inverse dissolubility for the oil-saturated reservoir. It can be explained by the fact that gas separates only from the oil and with the increase of the part of the water in the flow the mass of the separated gas decreases. It results in the decrease of the value of the cooling of gas separating. For example, for  $\varepsilon_1 = 0.04$  K/atm,  $c_1 = 2000$  J/kgK,  $q = 160$  kJ/kg,  $\bar{\rho} = 0.001$  we shall receive under  $WOR=0$  the value of dissolution  $\alpha_{inv}^1 = 0.5$  atm<sup>-1</sup>, corresponding to the small gas-oil ratios of the wells  $\Gamma = (50-60)$  m<sup>3</sup>/m<sup>3</sup> under the saturation pressure near 100-120 atmospheres. Under  $WOR = 1$ , which corresponds to the ratio between the flow rates of water and oil as  $Q_3 \approx 0.8 Q_1$ , inverse dissolubility is  $\alpha_{inv}^1 = 1$  atm<sup>-1</sup> and gas-oil ratio must not be less than  $\Gamma = (100-120)$  m<sup>3</sup>/m<sup>3</sup>.

4. **Under  $\varepsilon^* < 0$**  temperature of the gas-oil mixture coming from the reservoir decreases during the time  $t_l$  and at the moment of time  $t_l$  reaches the minimum value equal to  $\Delta T_{min} = \varepsilon^* \Delta P_1$ . Leaving in  $\varepsilon^*$  small values of the same order for the estimation  $\Delta T_{min}$  we receive

$$\Delta T_{min} \approx \left( \varepsilon_{13} - \frac{q \alpha \bar{\rho}}{c_1 + c_3 WOR} \right) \Delta P_1. \quad (28)$$

We can estimate the sign and value of the expected temperature decreases using the formula (28). Obviously, negative temperature anomaly at that moment is observed under the condition  $\alpha > \alpha_{inv}^1$ .

5. Temperature increases for  $t > t_l$ . From the certain moment  $t^*$  temperature anomaly becomes positive. Obviously, in that case the positive temperature anomaly will be observed in the long time working well. However, in the first period of production the negative temperature anomaly can be registered during the time  $t^*$  in the well. As long as such non-monotonous temperature change in time is typical for the oil degassing in the reservoir we can use it for the estimation of the behavior of the reservoir saturation. Time  $t^*$  can be estimated from the formula

$$t^* \approx t_1 \exp \left[ \left( \frac{\alpha}{\alpha_{inv}^1} - 1 \right) \cdot \frac{\Delta P_1}{\Delta P_2} 2 \ln \left( \frac{R_e}{r_s} \right) \right] \quad (29)$$

6. Steady value of the temperature anomaly equal is reached  $\varepsilon^* \Delta P_1 + \varepsilon_{13} \Delta P_2$  at the moment  $t_1 + t_2$ .

7. We can estimate an inverse value of dissolution at which the stable temperature anomaly equal to 0 from the ratio

$$\alpha_{inv}^2 \approx \frac{\varepsilon_1 c_1 + \varepsilon_3 c_3 WOR}{q \bar{\rho}} \frac{\Delta P}{\Delta P_1}.$$

as we can see,

$$\alpha_{inv}^2 = \alpha_{inv}^1 \frac{\Delta P}{\Delta P_1}.$$

**Calculation results analysis.** A calculator was developed for the calculations according to the formula (24). It represents a tool which allows evaluating not only temperature change in the wellbore with time, but also obtaining the numerical value of water-oil ratio, phase permeabilities, watercut and effective Joule-Thomson coefficients. The program makes it possible to change any parameters of the model and writes down the calculation results to the file. During the modeling progress demonstration of temperature change is provided. Favorable graphical interface.

Some constraints which were received using this calculator are given below. Tcharniy's phase permeabilities are used during modeling:

$$k_1 = \begin{cases} 0, & s_1 \leq 0.15 \\ (3.4 - 2.4s_1) \cdot \left( \frac{s_1 - 0.15}{0.85} \right)^{2.8} & s_1 > 0.15 \end{cases}$$

$$k_2 = (s_2)^{3.5} \cdot (1 + 3(1 - s_2))$$

$$k_3 = \begin{cases} 0, & s_3 \leq 0.2 \\ \left( \frac{s_3 - 0.2}{0.8} \right)^{3.5} & s_3 > 0.2 \end{cases}$$

Mass concentration of gas dissolved in oil can be estimated from

$$g = \frac{\rho_2^0}{\rho_1^0} \alpha p,$$

and solubility coefficient under the oil-gas ratio  $\Gamma$  given and saturation pressure  $P_s$  known is posed to

$$\alpha = \Gamma / P_s.$$

If it is not specially indicated value in the figure's captions or in the text it means that during the calculation the following values of the parameters are used

### Oil:

density	$\rho = 800 \text{ kg/m}^3$
compressibility	$\beta = 0$
specific heat capacity	$c = 1880 \text{ J/kgK}$
viscosity	$\mu = 0.005 \text{ Pa s}$
saturation pressure	$P_s = 120 \text{ bar}$
Joule-Thomson coefficient	$\varepsilon = 4 \cdot 10^{-7} \text{ K/Pa}$
adiabatic coefficient	$\eta = 0 \text{ K/Pa}$
degassing heat	$q = 160 \text{ kJ/kg}$

### Water:

density	$\rho = 1000 \text{ кг/м}^3$
compressibility	$\beta = 0$
specific heat capacity	$c = 4200 \text{ J/kgK}$
viscosity	$\mu = 0.001 \text{ Pa s}$
Joule-Thomson coefficient	$\varepsilon = 2 \cdot 10^{-7} \text{ K/Pa}$
adiabatic coefficient	$\eta = 0$

### Gas:

density	$\rho = 0.8 \text{ кг/м}^3$
specific heat capacity	$c = 3200 \text{ J/kgK}$
viscosity	$\mu = 2 \cdot 10^{-5} \text{ Pa s}$
Joule-Thomson coefficient	$\varepsilon = -4 \cdot 10^{-6} \text{ K/Pa}$
adiabatic coefficient	$\eta = 0$

### Reservoir skeleton:

density	$\rho = 2200 \text{ кг/м}^3$
compressibility	$\beta = 0$
specific heat capacity	$c = 1800 \text{ Дж/кгК}$
porosity	$m = 0.2$
permeability	$k = 0.2 \text{ D}$

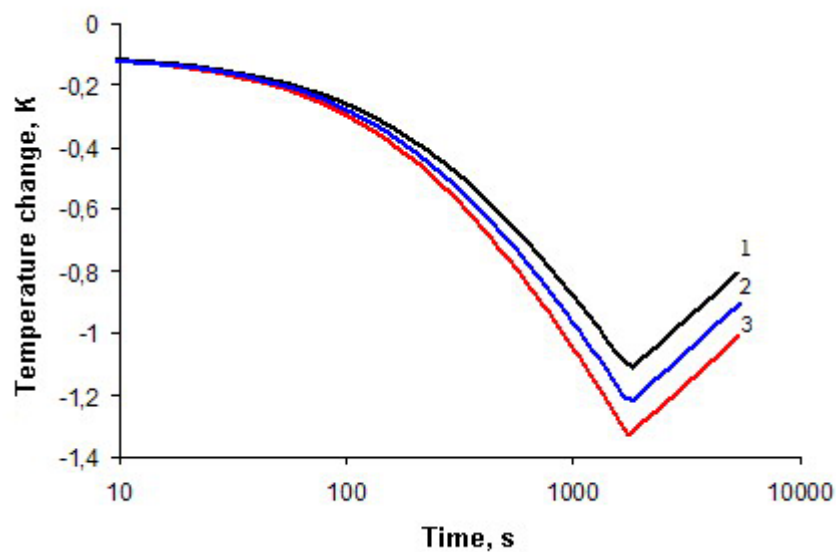
### Geometric parameters of the reservoir, initial and boundary conditions:

$$r_s = 108 \text{ mm}, R_e = 50 \text{ m}$$

$$P_r = 200 \text{ bar}, P_w = 100 \text{ bar}, \Gamma = 120 \text{ m}^3 / \text{m}^3$$

$$s_w^0 = s_w^0 = 0.3; \quad s_g^0 = s_g^0 = 0; \quad s_o = 1 - s_w - s_g$$

The dependences of the temperature changes on the wellbore wall with time for three various variants of calculations according to the formula (24) are given in the fig. 3.



**Fig. 3.** Analytical solution with three various options of calculation  
 Curve number – the degree of gas influence: 1 – minimal,  $g=g_s$ ;  
 2 – average,  $g= g_s+ g_w$ ; 3 – maximal,  $g=g_w$ .

It can be seen that:

- for all cases pattern of change with time is the same;
- stabilization time of the processes within degassing zone  $t_l$  changes slightly. It means that the velocity of temperature change is defined by the convective heat transfer of oil and water on the whole, but influence of the heat transfer by gas phase is low because of the small mass flow rate of gas;
- maximum difference in the value of the temperature change for various variants doesn't exceed 10%. The following calculations on the calculator were performed with the first variant of the calculation ( $g=g_s$ ).

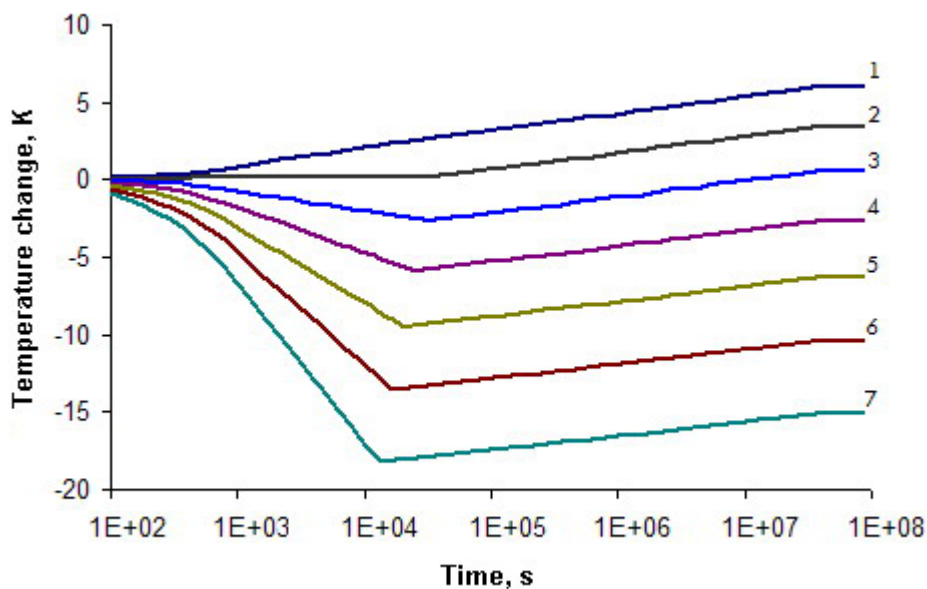
Series of the curves of the temperature change in time for various gas-oil ratios are given in the fig. 4. It is seen that with the increasing of the gas-oil ratio the value and observing time of negative temperature anomaly in the wellbore increase. For the accepted default settings with the gas-oil ratio 50 implements the case closed to the described above one with  $\varepsilon^*=0$ , when temperature on the bottom-hole of the well is practically constant during the time  $t_l$ . Obviously, temperature changes will be of little information in that case. Also it is seen from the curves that under the gas-oil ratio near 200 small temperature anomalies will be after stabilization of the temperature distribution in the long time production well.

Fig. 5 illustrates calculations for different values of water saturation in reservoir. It is evident that increase of the water fraction decreases cooling due to oil degassing.

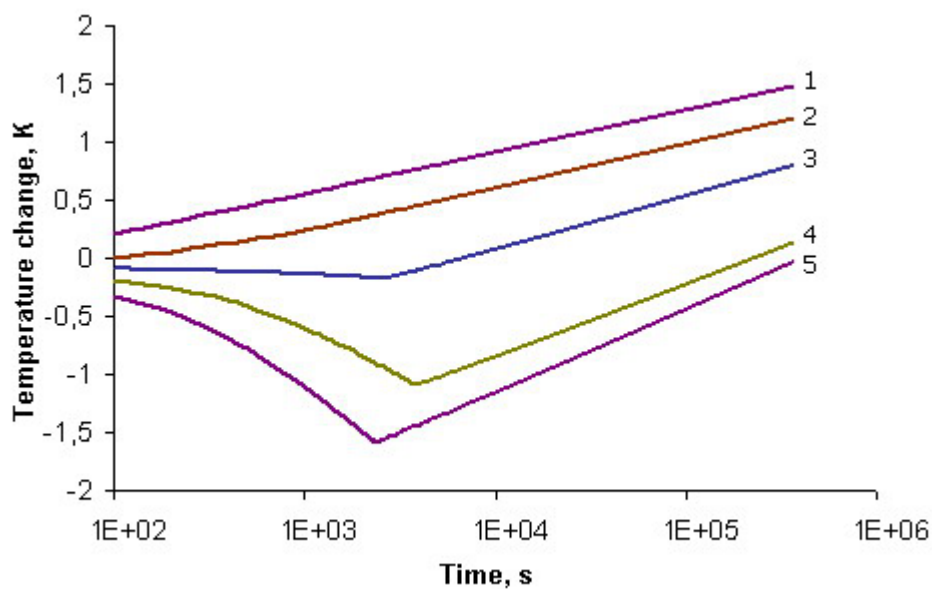
In Fig. 6 dependence of the value of temperature anomaly on the bottom-hole on water saturation for various moments of time is shown.

These dependences are easily explained by the physical processes in the reservoir taking into consideration diagrams of the phase permeabilities. So, with change of the water saturation from 0 to 0.2 water filtration is absent, appearance of water changes heat capacity of the reservoir and mass of the selected gas from the volume unit of porous media. All these facts influence on the temperature change.

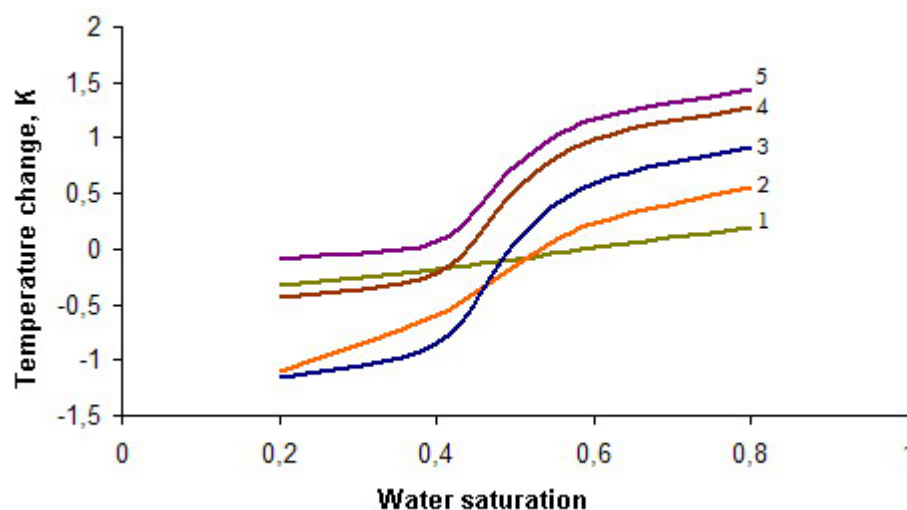
In Fig. 7 diagram of phase permeabilities is presented.



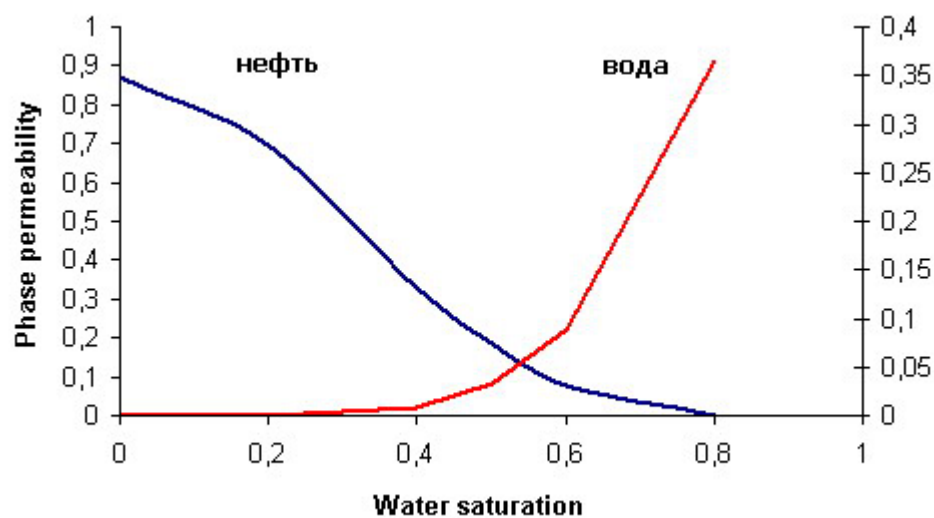
**Fig. 4.** Temperature change on the bottom-hole of the wellbore with time. Curve number – gas-oil ratio,  $\text{m}^3/\text{m}^3$ : 1 – 0; 2 – 50; 3 – 100; 4 – 150; 5 – 200; 6 – 250; 7 – 300.



**Fig. 5.** Temperature change on the bottom-hole of the wellbore with time. Curve number – water saturation, unitless: 1 – 0,8; 2 – 0,6; 3 – 0,4; 4 – 0,2; 5 – 0.



**Fig. 6.** Value of temperature change on the bottom-hole of the wellbore depending on values of water saturation in the reservoir for various moments of time. Curve number – time, s: 1 – 100; 2 – 1000; 3 – 10 000; 4 – 100 000; 5 – 300 000.



**Fig. 7.** Diagram of phase permeabilities.

With increase of the watering of production the cooling influence of oil degassing decreases. Under the water saturation more than 50% we shouldn't expect negative temperature anomalies regardless to the registration time of temperature logs as it follows from the figure. The temperature anomalies will be small with water saturation close to 0.5.

## Conclusions

1. Received formulas allow us to investigate the dependence of the typical times and values of the temperature anomalies on separate processes and reservoir parameters. For example, observing time of maximum value of the temperature drop  $t_l$  is defined by the radius of the degassing zone and rate of convective heat transfer (which is strongly depends on specific flow rates of oil and water) and this time can be used for estimation of these parameters.
2. With increase of water saturation naturally decreases the influence of the cooling effect of the oil degassing. Under the water saturation more than 50% the negative anomalies on the bottom hole of the wellbore from oil degassing is impossible to observe.
3. The calculator is developed on basis of the received solution. It allows to see the dependence of the value of temperature change on the bottom-hole of the well with time for the taken parameters of the model and to save the results of calculation in the text file.
4. The results of this work for well survey and reservoir evaluation can be used in different ways. For instance, during the production management it is possible, specifying numerical parameters of the model, to evaluate expected time of the temperature change with time in the well, or else to compare various working assumptions about the origin of temperature anomalies during interpretation of temperature survey.

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