Simulation of Time-Lapse Resistivity Logging During Two-Phase Well Testing in Petroleum Reservoirs

O A Shishkina¹², I M Indrupskiy¹, K V Kovalenko¹², A A Makarova², E S Zakirov¹, D P Anikeev¹ and E S Anikeeva¹

¹Oil and Gas Research Institute of Russian Academy of Sciences (OGRI RAS)
²National University of Oil and Gas «Gubkin University»

shishkinaolga.an@gmail.com

Abstract. Well testing methods are widely used in petroleum industry to identify reservoir parameters in-situ, at real reservoir flow conditions. Two-phase tests with water injection extend capabilities of well testing to evaluation of oil-water flow characteristics through the solution of an inverse problem based on well measurements during the test. Near-wellbore water saturation is used as one of the informative measured parameters. However, water saturation is actually not directly measured on wells. Instead, it is interpreted from time-lapse well logging data, with resistivity logging being one of the options. This means that forward and inverse problems are to be extended to incorporate direct simulations of resistivity logging. In this paper we address the forward problem. It is formulated and solved for different types of logging tools, both for open hole and through the casing. A numerical algorithm and software implementation have been developed for repeated solution of an axisymmetric forward problem of resistivity logging – a 2D elliptical partial differential equation for electrical potential. Distributions of formation resistivity at the moments of logging are calculated from distributions of water saturation and salinity. The latter are computed through numerical solution of the forward problem of well testing – a two-phase oil-water flow in the reservoir with changing salinity of the water phase, with full account for real fluid and reservoir properties. The software implementation of the resistivity logging problem has been tested in comparison with the known theoretical solutions. Examples are presented to show how time-lapse changes in resistivity logging data reflect the specifics of the two-phase flow with changing water salinity during the well test.

1. Introduction

The development of oil fields requires the most complete and accurate knowledge of the reservoir properties and processes taking place in it during production. The most important characteristics of the oil displacement process – the displacement efficiency ($E_{disp}$) and the relative permeability (RP) curves – are traditionally determined from the results of core studies. This leads to two types of principal discrepancies. On the one hand, core studies are associated with irremovable deviations of wettability and other rock characteristics from actual reservoir conditions. On the other hand, the results are influenced by a significant difference in scale of flow processes in a core experiment and during actual reservoir development [1].

Well tests (WT) are used to determine formation properties in-situ, in real reservoir flow conditions. Traditional well testing techniques and data interpretation are based on solutions of underground flow problems in single-phase formulation, thus excluding the possibility to determine...
RP curves and other important parameters of multiphase flow. Some studies on the development of well testing methods with the assessment of current or endpoint RP for oil and water were presented in [2,3]. A theoretical work on evaluation of RP curves from well tests was reported in [4].

An integrated approach to the assessment of $E_{disp}$ and RP curves for oil and water at reservoir conditions has been developed since 2001 at Oil and Gas Research Institute of RAS [5]. The approach includes a combination of specialized two-phase well testing with periodical well logging to control saturation changes in the near-wellbore zone and analysis of salinity dynamics for the water phase due to mixing of formation water (brine), injected water and residual operational fluids [6-8].

Previous experience with saturation logging [6,8] was associated with cased boreholes and the use of pulsed neutron-neutron logging (PNNL) to monitor changes in near-wellbore water saturation. To ensure informative measurements by this method, the injection of brine solutions was applied. In the ideologically similar studies [9], a special type of multi-probe resistivity logging tool was used for an open-hole well in a massive carbonate reservoir. Other potential applications for resistivity logging in two-phase well testing are associated with the use of non-metal casing or resistivity logging through the metal casing with special logging tools.

In the interpretation of the two-phase well testing results, an inverse problem is formulated and solved to obtain the required reservoir characteristics, including the RP curves for oil and water. Input data for the inverse problem are the dynamics of bottomhole pressure, water cut and salinity of the produced water phase measured at the well [5-8]. Additionally, estimates of the near-wellbore water saturation obtained from time-lapse logging are used. Saturation data are subject to methodological errors, since traditional log interpretation does not take into account the dynamics of two-phase flow in the reservoir and changes in salinity. To resolve this issue, it is necessary to consider a joint solution of, firstly, the forward problem, and then the inverse problem of well testing and well logging.

This paper considers the joint forward problem of two-phase well testing and resistivity logging. The forward problem, in turn, is a necessary element of the iterative solution of the inverse problem [5,8].

2. Two-phase well testing

The technology of two-phase well testing is based on creation of essentially two-phase flows in the reservoir, with wide-range changes in water saturation in the near-well zone. The idea of the method is schematically illustrated in Fig. 1.

In the simplest case, the technology assumes the following sequence of well operation regimes [5].

1. Up to the time $T_1$, the well produces reservoir fluid (oil) with a specified (possibly variable) flow rate.
2. From $T_1$ to $T_2$, the well is stopped, and the pressure build-up (PBU) curve is recorded.

![Figure 1. Conventional (single-phase) and proposed (two-phase) approaches to oil well testing](image-url)
3. From T₂ to T₃, water (brine) is injected into the reservoir with a specified (possibly variable) flow rate and controlled composition (salinity), generally different from that of reservoir water.

4. From T₃ to T₄, the reservoir mixture (oil and water) is produced with a specified (possibly variable) liquid flow rate.

Several well equipment setups are suitable for this sequence of operations, based on a jet pump, a bypass system (Y-tool), etc. [6-8].

In response to these operations, bidirectional two-phase fluid flows are created in the reservoir, which provide more informative measurements and simulations compared to mainly single-phase fluid flows in conventional well tests.

For simulation of these processes, we consider a mathematical model of unsteady 1D axisymmetric two-phase flow of compressible immiscible liquids (oil and water) in a compressible porous medium [5]. The continuity equations and the generalized Darcy’s law are:

\[
\frac{\partial}{\partial t} (\phi S_{\alpha} \rho_{\alpha}) + \frac{\partial}{\partial r} (\rho_{\alpha} v_{\alpha}) = 0, \quad \alpha = o, w, \tag{1}
\]

\[
v_{\alpha} = -\frac{k k_{\alpha}}{\mu_{\alpha}} \frac{\partial p_{\alpha}}{\partial r}, \tag{2}
\]

where \( r \) is the radial coordinate; \( t \) is the time; \( p_{\alpha} \) is the pressure in phase \( \alpha \) (\( \alpha = o \) corresponds to the oil phase, and \( \alpha = w \) to the aqueous/water phase); \( S_{\alpha} \) is the saturation of the porous medium with the phase \( \alpha \); \( \rho_{\alpha} \) and \( \mu_{\alpha} \) are the density and viscosity of the phase \( \alpha \); \( \phi \) and \( k \) are the porosity and permeability of the porous medium (reservoir); \( k_{\alpha} \) is the relative permeability to the phase \( \alpha \); \( v_{\alpha} \) is the Darcy velocity of the phase \( \alpha \). Combining (1) and (2) and using the logarithmic spatial coordinate \( u = \ln \left( \frac{r}{R_b} \right) \), where \( R_b \) is the external radius of the drainage area, we obtain the following system of nonlinear partial differential equations:

\[
\frac{\partial}{\partial u} \left( \frac{k k_{\alpha}}{\mu_{\alpha}} \frac{\partial p_{\alpha}}{\partial u} \right) = R_b^z e^{2u} \frac{\partial}{\partial t} (\phi S_{\alpha} \rho_{\alpha}), \quad \alpha = o, w. \tag{3}
\]

To account for variable salinity of the aqueous (water/brine) phase, it is convenient to introduce effective porosity \( \phi_{eff} \) in equations (3) and renormalize saturation by the effective pore volume [5], i.e. to consider bound (immobile) water separately as it may have different salinity (in this work it is assumed equal to salinity of the mobile water). Then mass balance equation for salt in the aqueous phase (salt transport equation) is added to the system (3):

\[
\frac{\partial}{\partial u} \left( \frac{k k_{\alpha}}{\mu_{w}} \frac{\partial l_{sw}}{\partial u} \right) = R_b e^{2u} \frac{\partial}{\partial t} \left( \phi_{eff} S_{sw} \rho_{sw} l_{sw} + M_{sw} l_{sw} \right), \tag{4}
\]

where \( l \) is the sat concentration in the mobile aqueous phase (salinity); \( l_{sb} \) is the salt concentration in bound water; \( M_{sb} \) is the mass of bound water per unit volume of the reservoir, and tilde in \( S \) means that saturation is normalized by the effective pore volume.

The equations (3)-(4) are supplemented with initial conditions – distributions of oil pressure, water saturation and salinity at the beginning of the test. Boundary conditions are set corresponding to the technologically determined stages 1-4 of the well test [5].

The closing relations are the normalization condition for saturations:

\[
S_{o} + S_{w} = 1 \tag{5}
\]

and the relations for reservoir and fluid properties:

\[
p_{o} = p_{w} = p_{cap}(S_{sw}),
\]

\[
\rho_{o} = \rho_{w}(\rho_{w}),
\]

\[
\mu_{o} = \mu_{w}(\rho_{w}),
\]

\[
k_{\alpha} = k_{\alpha}(S_{\alpha}). \quad \alpha = o, w. \tag{6}
\]
Here $P_{\text{cap}}(\tilde{S}_w)$ is the capillary pressure, which is the function of water saturation. The relations (6) can be modified to account for the effect of salinity on the density and viscosity of the aqueous phase, as well as relative permeabilities and capillary pressure.

Equations (3)-(6) form a closed system of partial differential equations for oil pressure, water saturation and salt concentration. It is solved using a fully implicit control-volume scheme, with upwind weighting for saturations and salt concentration. As the result, distributions of reservoir pressure, water saturation and salinity are obtained for every moment of the well test, which forms the basis for simulation of time-lapse resistivity logging.

3. Simulation of resistivity logging

Resistivity logging is based on the apparent resistivity theory [10]. The measurements are performed with an electrical tool (sonde) lowered into the well. The recorded parameter is the apparent resistivity (AR), which is calculated from the potential difference between the measuring (potential) electrodes installed on the tool. The potential difference is caused by the current flow through the formation generated by the current (source) electrode.

Two types of tools are widely used to determine the AR in open-hole wellbores: normal and lateral devices. Their fundamental difference is the relative position of the current electrode A and two potential electrodes M and N, as well as of the point O, which corresponds to the recorded measurement (Fig. 2).

![Figure 2. Basic types of tools for resistivity logging in open-hole wellbores](image)

To determine the AR in cased wellbores, significantly different tools are used. They contain three or more potential electrodes (M, Ni), and may also contain several current electrodes (Ai). There have been many studies on the applicability of such devices, and each of them has certain specifics in tool design and interpretation. Their common idea is to use focusing of the generated electrical field to overcome issues related to the high conductivity of the metal casing. In this study, we consider a basic (theoretical) version of a tool with focused potential electrodes shown in Fig. 3 [11].

![Figure 3. Schematic representation of a basic cased-hole resistivity logging tool](image)
To obtain the distribution of AR over the formation thickness, sequential measurements with a certain step in depth are performed with a logging tool. The type and size of the tool determines the radius (penetration depth) of the study and configuration of the AR curves recorded in layered formations.

The forward problem of resistivity logging consists in the simulation of the potential field in the formation and calculation of the corresponding AR readings. Analytical solutions can be obtained for cases with simplified geometries of the reservoir and well [10,11]. In other cases, numerical simulation is used. It is based on the solution of a variable-coefficient elliptic equation for electrical potential.

The field of electrical potential $U$ in a saturated porous medium satisfies the differential equation:

$$
\text{div}(\sigma \cdot \nabla U) = -g, \quad (7)
$$

$$
\sigma = \frac{1}{\rho_{\text{res}}} \quad (8)
$$

where $g$ is the current density (source term), $\sigma$ is the electrical conductivity and $\rho_{\text{res}}$ is the resistivity of the saturated medium.

In the case of two-phase well testing, the distributions of water saturation and salinity at the moments of resistivity logging are known from the solution of the forward flow problem (3)-(6). Then resistivity of the saturated porous medium at each location can be calculated with a chosen petrophysical model. As an example, in this study we use the generalized Archie-Dakhnov formula [12,11]:

$$
\rho_{\text{res}} = a \cdot \phi^{-m} \cdot \rho_{br}(r, t) \cdot S_w(r, t)^{-n}, \quad (9)
$$

where $a$ is an empirical parameter; $m$ is the cementation factor; $\rho_{br}$ is the resistivity of brine (aqueous phase); $n$ is the saturation exponent. The parameters $a$, $m$ and $n$ depend on the rock type and pore structure and are determined for a particular formation through petrophysical analysis.

The resistivity of brine can be calculated with the empirical Darley’s formula [13]:

$$
\rho_{br}(r, t) = \left(0.0123 + \frac{3647.5}{c_s^{0.955}(r, T)} \right) \cdot \frac{82}{1.87 + 39}, \quad (10)
$$

where $c_s$ is the salt concentration in brine (in ppm), $T$ is the temperature in °C.

Since the parameter distributions obtained from the solution of the forward flow problem (3)-(6) have different normalization and units from those used in (9)-(10), conversion is required. If differences in the mobile and bound water salinity are taken into account then appropriate petrophysical models for formation resistivity are to be used [10,14].

With regard to the two-phase well testing, the forward problem of resistivity logging is solved in a 2D axisymmetric formulation. If the flow problem is solved in 1D, the reservoir is divided into a set of layers with the same properties corresponding to the parameter distributions calculated from the solution of the flow problem at current moment in time. Extra layers with formation resistivity typical for clays are added above the top and below the bottom of the reservoir to take into account their effect on the AR curves. The grid along the radial coordinate is supplemented with “borehole” cells in the region $r_s \leq r \leq r_w$, where $r_s$ is the radius of the sonde (tool), $r_w$ is the radius of the wellbore. In this region, resistivity is set equal to the resistivity of brine $\rho_{br}$ in the open-hole case, or to a low value of wellbore resistivity $\rho_{mc}$ in the cased-well case considering the effect of metal casing in contact with the sonde. The equation (7) for the forward problem of resistivity logging takes the form:

$$
\frac{1}{r} \frac{\partial}{\partial r} \left(r \sigma(r, z, t) \frac{\partial U}{\partial r} \right) + \frac{\partial}{\partial z} \left(\sigma(r, z, t) \frac{\partial U}{\partial z} \right) = -g. \quad (11)
$$

The boundary conditions are as follows:

$$
\frac{\partial U}{\partial r} \bigg|_{r = r_s} = U \bigg|_{r = R_b} = U \bigg|_{z = \pm \frac{h}{2}} = 0, \quad (12)
$$
where \( h \) is the total thickness of the modeled area, and the vertical coordinate \( z \) is measured from the mean depth of the reservoir. These conditions correspond to sufficiently distant external boundaries of the modeled area (computational domain) from the source electrode and the presence of only vertical (along the tool) current at the sonde surface.

For a fixed time of logging and position of the source, the problem (11)-(12) is solved with a control-volume numerical scheme. Logarithmic transformation of the radial axis \( x = \ln(r) \) gives a possibility to use a uniform mesh in \( x \) and \( z \) while preserving high radial resolution near the wellbore. The obtained system of linear algebraic equations is solved by the biconjugate gradient method.

As soon as the potential field \( U(r, z) \) is computed, the potentials at the measuring electrodes are used to calculate the AR. In the open-hole case, the AR can be found as [10,11]:

\[
\rho = K \frac{\Delta U}{T},
\]

where \( \rho \) is the AR; \( K \) is the sonde factor; \( \Delta U \) is the potential difference between the measuring electrodes \( M \) and \( N \); \( I \) is the current generated at the source electrode. The sonde factor is computed by:

\[
K = 4\pi \cdot \frac{AM \cdot AN}{MN}.
\]

For the cased-hole case with the tool configuration from Fig. 3, the AR is calculated by:

\[
\rho = \frac{\rho_{lm} U_M}{\pi G r_w^2 U_M^\prime\prime}
\]

where \( U_M \) is the potential at the measuring electrode \( M \); \( U_M^\prime\prime \) is the second derivative of potential with respect to \( z \) computed numerically using the potentials at electrodes \( M \), \( N_1 \) and \( N_2 \); and \( G = \frac{1}{2\pi} \ln \left( \frac{R_k}{r_w} \right) \).

For other cased-hole tool configurations, the AR computation is changed accordingly.

To construct the simulated AR curve (AR versus depth) at a certain logging moment, the described solution procedure is repeated for successive vertical positions of the tool (source and measuring electrodes) within the formation with a selected step in depth. The simulated AR log corresponds to a selected type well completion (with or without metal casing) and tool (by type and geometric parameters).

For time-lapse resistivity logging during two-phase well testing, the forward electrical problem is solved and the AR curve is calculated repeatedly for every moment of logging. The solution is based on current distributions of water saturation and salinity from the flow simulation. The software implementation includes internal data exchange between the flow and logging parts of the algorithm.

4. Synthetic test-case simulations

The algorithm and software implementation of the forward electrical problem was thoroughly tested against analytical solutions for different tool and reservoir configurations.

To test the joint solution of the flow and electrical forward problems and analyze the specifics of AR changes during the two-phase well test, the following synthetic case was considered.

The main input data are presented in Table 1. The dependences of fluid properties on pressure, and RP and capillary pressure on water saturation correspond to the initial data of the test case given in [5].

The stages of the test are:

1) 240 hours production with the liquid (oil) rate of 50 m³/day
2) 240 hours of pressure build-up;
3) 96 hours of water (brine) injection with the rate of 100 m³/day and salt concentration of 0.03 g/g;
4) 160 hours of two-phase liquid production with the rate of 75 m³/day.

Resistivity logging with a lateral device is carried out at the beginning of the study \((t = 0)\), in the middle and at the end of the injection stage \((t = 526)\) and \(t = 560\) hours from the beginning of the
test, respectively), and in the middle and at the end of the two-phase liquid production stage ($t = 642$ and $t = 736$ hours from the beginning of the test, respectively).

**Table 1. Initial data for the synthetic test case**

| **Reservoir properties** |  |
|--------------------------|--|
| Configuration of the reservoir (drainage zone) | circular, piecewise homogeneous (with a skin zone) |
| Radius of the external boundary, m | 500 |
| Well radius, m | 0.1 |
| Top depth of the formation, m | 2000 |
| Formation thickness (with clay intervals), m | 40 |
| Oil-saturated reservoir thickness, m | 15 |
| Resistivity of clays, ohm·m | 2 |
| Effective porosity of the reservoir | 0.16 |
| Effective permeability of the reservoir, μm² | 0.5 |
| Reservoir temperature, °C | 50 |
| Initial reservoir pressure, bar (1 bar=10⁵ Pa) | 200 |
| Conditional radius of the skin zone, m | 0.032 |
| Conditional permeability of the skin zone, μm² | 0.025 |
| Equivalent skin factor | 5.275 |

| **Fluid properties** |  |
|---------------------|--|
| Oil viscosity at reservoir conditions, mPa·sec | 5 |
| Water viscosity in reservoir conditions, mPa·sec | 1 |
| Oil density at standard conditions, kg/m³ | 810 |
| Water density at standard conditions, kg/m³ | 1300 |
| Initial and bound water saturation – normalized by total / effective pore volume | 0.2 / 0 |
| Residual oil saturation – normalized by total / effective pore volume | 0.2 / 0.25 |

| **Parameters of the Archie-Dakhnov formula** |  |
|--------------------------|--|
| $a / m / n$ | 1.0 / 2.0 / 2.0 |

Two cases for the initial distribution of bound water salinity were considered (Fig. 4).
1. The salinity is constant and corresponds to the salinity of the formation water (Fig. 4a).
2. In a local zone around the wellbore, salinity corresponds to the unrecovered (immobile) part of the operational fluid, which got into the reservoir and replaced the formation water during completion and tripping operations (Fig. 4b). Such a distribution was noted during two-phase testing of a real well [8].
Two lateral devices of different sizes were selected for simulation. Tool marked as A2M0.5N corresponds to the distances $AO = 2\, m$, $MN = 0.5\, m$; tool A4M0.5N $– AO = 4\, m$, $MN = 0.5\, m$. The current at the source was $I = 0.5\, A$. The AR logs were calculated with an uneven step of the tool movement along the wellbore: the step in the clays was greater than in the oil-saturated reservoir.

The results of the AR simulations for the first and second cases of the initial salinity distribution are shown in Fig. 5 and 6, respectively (in logarithmic scale).

It can be seen in Fig. 5-6 that changes in the AR logs over time clearly reflect the processes occurring during the two-phase well test. Water injection leads to a decrease in the AR. Subsequent production of the two-phase mixture, with a gradual increase in oil saturation in the near-wellbore zone, is characterized by a corresponding backward increase in the AR. The distinct difference between the lateral log curves at the considered moments in time indicates the possibility of obtaining reliable data on near-wellbore water saturation dynamics during the well test.
Comparison of Fig. 5 and 6 for each of the tools indicates a significant quantitative difference in the AR curves for the two cases of initial salinity distribution. Despite the same dynamics of water saturation, different salinity of the mixed aqueous phase formed in the near-wellbore zone significantly affects the AR logs both before and after the injection stage. Consequently, conclusions of the paper [8] are confirmed. Namely, for reliable interpretation of time-lapse well logging data, thorough control of produced water composition and analysis of well operation history are required.

The differences observed in Fig. 5 and 6 in log shapes and AR values between the two tools are related to their sizes. The masking effect at the top of reservoir is stronger for the larger tool. Also, specifics of potential distribution during the tool operation are such that the AR readings are most influenced by resistivity of an annular zone of the reservoir located at a distance from the well approximately equal to the tool size. The both noted observations are in accordance with theory and practice of lateral logging and confirm adequacy of the simulation results.

5. Conclusions
The formulation of a joint forward problem of two-phase flow and resistivity logging presented in the paper provides correct simulation and interpretation of the time-lapse lateral logging data acquired during complex two-phase well testing. The developed numerical algorithm and software implementation provide a consistent internal data exchange and the ability to calculate resistivity logs for different type of tools at any moment of the well test. The numerical implementation for AR log simulation was thoroughly tested by comparison with theoretical solutions.

The presented synthetic-case simulations demonstrated specifics of reservoir processes during two-phase well testing and confirmed the adequacy of simulated AR data. They show possibility of reliable assessment of the near-wellbore water saturation dynamics taking into account mixing of injected brine with formation water and residual operational fluids.

Acknowledgement
The paper was prepared within the State Research Contract of OGRI RAS (topic AAAA-A19-119022090096-5 for O.A.Shishkina, I.M.Indrupskiy, E.S.Zakirov, D.P.Anikeev and E.S.Anikeeva, and topic AAAA-A19-119030690047-6 for K.V. Kovalenko).
References

[1] Nikolaev V A, Zakirov S N and Zakirov E S 2011 New Concepts about the Displacement Efficiency of Viscous Oils Based on Laboratory Experiments *Doklady Earth Sciences* **436** 1 p 6-8

[2] Kamal M M (ed.) 2009 *Transient Well Testing* SPE Monograph Series **23** (Richardson: Society of Petroleum Engineers) p 850

[3] Kremenetsky M I, Ipatov A I and Gulyaev D N 2012 *Information Support and Technologies for Flow Modeling of Oil and Gas Deposits* (Moscow-Izhevsk: Institute for Computer Research) p 896 (in Russian)

[4] Chen S., Li G., Peres A. and Reynolds A.C. 2008 A Well Test for In-Situ Determination of Relative Permeability Curves *SPE Res. Eval. & Eng.* **11** 1 p 95–107 SPE Paper 96414

[5] Zakirov S N, Indrupskiy I M, Zakirov E S et al. 2009 *New Principles and Technologies of Oil and Gas Field Development* Part 2 – (M.-Izhevsk: Institute for Computer Research) p 484 (in Russian)

[6] Indrupskiy I M, Zakirov E S, Anikeev D P, Ipatov A I, Fakhretdinov R N, Gulyaev D N and Klochan I P 2008 Evaluation of Relative Permeabilities at Downhole Conditions *Oil Industry* **2008** 5 p 39-42 (in Russian)

[7] Zakirov S N, Indrupskiy I M, Zakirov E S et al. 2012 Well Test for In-Situ Determination of Oil and Water Relative Permeabilities *SPE Russian Oil and Gas Exploration and Production Technical Conference and Exhibition* (Moscow, Russia) SPE Paper 162011-MS. https://doi.org/10.2118/162011-MS

[8] Zakirov S N, Indrupskiy I M, Zakirov E S et al. 2016 In-Situ Determination of Displacement Efficiency and Oil and Water Relative Permeability Curves through Integrated Well Test Study at Exploration-to-Pilot Stage of the Oilfield Development Project *SPE Russian Petroleum Technology Conference and Exhibition* (Moscow, Russia) Paper SPE 181967-MS. https://doi.org/10.2118/181967-MS

[9] Kuchuk F J, Zhan L, Ma M et al. 2010 Determination of In Situ Two-Phase Flow Properties Through Downhole Fluid Movement Monitoring *SPE Res. Eval. & Eng.* **13** 4 p 575–87 SPE Paper 116068-PA

[10] Bassiouni Z 1994 *Theory, Measurement and Interpretation of Well Logs* SPE Textbook Series **4** (Richardson: Society of Petroleum Engineers) p 384

[11] Gorbachev Yu I 1990 *Geophysical Well Logging* (Moscow: Nedra) p 398 (in Russian)

[12] Archie G E 1942 The Electrical Resistivity Log as an Aid in Determining Some Reservoir Characteristics *Petrol. Trans. AIME* **146** 1 p 54–62

[13] Darley H C H and Gray G R 1988 *Composition and Properties of Drilling and Completion Fluids* (Houston: Gulf Professional Publishing) p 643

[14] Afanasiev S V, Afanasiev A V and Ter-Stepanov V V 2008 A Generalized Model for Terrigenous Granular Rock Conductivity and Results of Its Testing *Karotazhnik* **2008** 12 p 36–61