About Identifiability of Oil and Water Relative Permeability Curves and Reservoir Heterogeneity through Integrated Well Test Study

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Abstract. Relative permeabilities (RP) play an important role in reservoir engineering. RP functions together with the permeability anisotropy coefficient predetermine waterflooding efficiency and oil/water ratio in production forecast. Traditionally multiphase flow parameters are estimated from core analysis data. But such measurements suffer from small representative elementary volume (REV) and limited characterization of reservoir properties. Therefore using core data in 3D reservoir modelling could lead to distorted description of actual flow conditions. Despite those functions (RP) could be history matched with assimilated production data, such a procedure would require long history of waterflooding. So the authors’ idea is to apply integrated well test study to estimate the displacement efficiency and/or relative permeability functions at downhole conditions. Well testing is traditionally applied in reservoir engineering for single-phase reservoir parameters estimation. Our approach is extended to multi-phase flow and is based on data collection at well bottomholes and subsequent data assimilation in flow model.

In this paper we summarize both features of mathematical problem statement and identifiability of multiphase parameters through inverse problem solution, but also discuss 10+-year experience in interpretation of two-phase well testing using our technologies. To estimate multiphase parameters, we have to jointly consider complex data of well logging and dynamic data of well testing. Both data sets are used in the inverse problem quality criteria, where the least squares method has been applied. Forward problem corresponds to a 3D multiphase fluid flow model in porous media. The latter consists of continuity equation with multiphase Darcy equation instead of moment balances. For data assimilation modern methods of optimal control theory were successfully applied. For all synthetic test cases real reservoir parameters were accurately recovered through the use of forward simulation data.

In order to estimate reservoir heterogeneity, we applied a single-phase model to get the ratio of vertical to horizontal permeability. Data of well self-interference testing were used for vertical permeability estimation. Depending on the depth of reservoir pressure perturbation, reservoir properties could be properly inferred from observations. Two other options of 3D interference testing using vertical and horizontal wells are also presented.

In other words, all the problems considered are identifiable, and the level of their correctness is completely predetermined by the amount and quality of observed data. And transition to digital (intelligent) oil-and-gas production and closed-loop reservoir management [1] provides a possibility to remove discussed restrictions and all inverse problems considered should be accounted as fully identifiable.
1. Introduction

Contemporary transition to 3D computer modeling for different technologies comparison has sharply raised the issue of obtaining accurate primary data on reservoir properties in 3D simulation models.

Fundamental problem of core and reservoir scales difference does not allow to rely on special core analysis data. Typical core size is a few centimeters, but characteristic grid cell areal size in a full-scale 3D flow model lies between 25 and 100 m. Therefore, reservoir heterogeneity with characteristic scale in meters could not be "represented" on the core scale, but at the same time it would affect the reliability of the 3D flow model. The most urgent problem is associated with relative permeabilities (RP). A typical situation can be represented by the following simple example. Usually there are hundreds or even thousands of measurements performed for a large field to evaluate open (or total) porosity and absolute permeability on cores. And for the same object, only a few RP pairs are determined in laboratory, often under certain simplifying assumptions.

There is always a lack of RP data obtained on cores. Both in terms of their representativeness, reliability and completeness. But even core data could not be directly transferred to a 3D flow model. Moreover, due to difficulties with fluid and core sampling, it is not always possible to work in the laboratory with real (corresponding to studied object) fluids and cores. In addition, differences in core and reservoir scales together with rock wettability distinction at reservoir and laboratory conditions represent itself a fundamental unavoidable problem.

There are many other examples clearly demonstrating the fact that well data cannot be directly applied to the entire volume of a 3D flow model. Some review of undertaken investigations is presented in [2].

Therefore, the idea of improving traditional well testing methods [3, 4] and their data interpretation remains urgent. Ideally it should give reliable estimates of RP and permeability at reservoir conditions, i.e. taking into account the anisotropy. This paper discusses various ways of conducting specialized well testing studies aimed at assessing relative permeabilities in-situ as well as directional permeabilities of the reservoir.

Gas-, Oil-, Condensate Recovery laboratory of Oil and Gas Research Institute of Russian Academy of Sciences has already proposed a whole range of technologies for well testing and methods for observed data processing. They served as the basis for publication of several books, a number of papers and patents [5-12]. It is also important to emphasize that necessity to create new technologies for well testing arose as a result of practical implementation of the effective pore space (EPS) concept [5, 11].

A common feature of the corresponding technologies consists in creation of multidimensional and/or multiphase flows in the reservoir. An inner part of those technologies is based on specialized algorithms for results interpretation using numerical methods for solving forward and adjoint boundary value problems, methods of optimal control theory (for inverse problem solution).

In general, all the mentioned technologies could be divided into two groups: methods of active well testing, including evaluation of relative permeabilities (WT-RP), and new methods for interference testing. Technologies for well testing aiming in relative permeability evaluation for oil and water at reservoir conditions are based on creation of two-phase multidirectional flows in the reservoir. A common feature of these studies involves implementation of the following typical sequence of technological operations.

● Stage I. As in traditional studies [3], the tested well is operated for producing oil for a certain period of time. The difference consists in the absence of special restrictions on oil flow rate, including its arbitrary variation in time. There is also no limitation on duration of the oil production interval.

● Stage II. The tested well is shut in for obtaining conventional bottomhole pressure build-up curve. At the same time, there is no requirement for bottomhole pressure restoration to the level of initial reservoir pressure.

● Stage III. Water is injected into the well, generally with a time-variable flow rate. Water injection continues for a predetermined time period.
Stage IV. The well is switched back to production. This means that it produces reservoir mixture (water and oil) with a given, possibly time-varying, liquid flow rate. In this case, the well produces the injected water first, then water-oil mixture, and subsequently, possibly, only pure oil.

Several cycles of fluid injection and production are quite possible. For example, in paper [12] two production and injection cycles were considered. The general approach to data interpretation assumes that corresponding inverse problem is performed for assimilating measurements obtained at I-IV stages.

Well testing technologies to evaluate permeability along various directions at reservoir conditions are based on creation of multidirectional flows in a reservoir. Common feature of such studies consists in the following typical sequence of technological operations [3].

- Stage I. At this period, the well is operated for fluid production or injection.
- Stage II. A well is shut in for conventional recording of bottomhole pressure build-up or drawdown curves depending on the operational mode at the first stage. At the same time, the requirement for bottomhole pressure restoration to the level of initial reservoir pressure is not directly stated.

Between individual stages and during technological breaks, additional investigations at the well are admissible, but it is also desirable to register changes in bottomhole pressure. Various ways of well operation are possible, but important requirement for reliable assessment of reservoir properties consists in complete exclusion of round trip operations with well killing in throughout the whole study.

General approach to data interpretation suggests that a corresponding inverse problem is stated. Evaluated reservoir parameters (in particular, permeability) are retrieved from data assimilation of measurements obtained during well testing stages. Mathematical problem statement of such a problem needs a specific quality criterion to minimize. For each problem, the quality criterion (the objective function) and a set of control parameters are determined based on peculiar features of the problem under investigation. Further, for each well testing technology we would present all the mentioned items separately. We would also pay special attention to identifiability, namely, possibility of retrieving true values of control parameters from observed data.

2. Mathematical problem statement and solution technique

For this type of problems, reservoir parameters are inferred from the inverse problem solution.

From mathematical problem statement it straightforwardly follows that a given objective function is required to be minimized. For each problem, the quality criterion (the objective function) and a set of control parameters should be determined based on peculiar features of the problem under investigation.

Depending on specific problem, measured values include certain well performance data and/or results of well logging data interpretation.

Reservoir parameters are inferred from the inverse problem solution. The solution algorithm provides sequential execution of the following stages:

- Solution of the forward flow problem.

The goal of the forward problem solution consists in obtaining the dynamics of measured parameters during well testing for given values of control parameters. Current value of the optimized quality criterion is evaluated. The quality criterion reflects the mismatch between calculated and actually measured values of well performance data.

For such a nonlinear forward problem, fully implicit, two-layer in time finite-difference (control volume) numerical scheme is traditionally applied. At every time step, the following nonlinear system of algebraic equations is to be solved:

$$\bar{F}^j(\bar{x}^j, \bar{x}^{j-1}, \bar{u}) = 0 \quad j = 1, 2, \ldots, N,$$

where $\bar{x}^j$ is the vector of independent variables (phase variables) of the forward problem on $j$-th time layer, $N$ is the number of time steps in the forward problem. For two-phase flow, $\bar{x}^j$ is the vector of
pressures in the oil phase and water saturations in each grid block at time layer \( j \). \( \bar{u} \) is the vector of control parameters (reservoir parameters, including relative permeabilities).

Boundary conditions correspond to the absence of flow through the external boundary and a special condition, selected depending on the well operating mode, according to the flow to/from grid cells completed by the well [13]. Initial condition corresponds to the solution of the static problem of gravity-capillary equilibrium.

The system of nonlinear equations (1) at each time step is solved with the Newton-Raphson method, which results in a set of linear algebraic equations at each iteration:

\[
\tilde{F}_x^j(\tilde{x}^{(v)}) \delta \tilde{x}^{(v)} = -\tilde{F}_x^j(\tilde{x}^{(v)})
\]

(2)

where \( v \) is the number of current iteration of the Newton-Raphson method, \( \delta \tilde{x}^{(v)} \) denotes the values of the next additives to the solution of nonlinear system (1), and \( \tilde{F}_x^j \) represents the matrix of partial derivatives (Jacobi matrix) of equations (1) at \( j \)-th time step with respect to the forward problem phase variables \( \tilde{x}^j \).

Thus, as a result of the forward problem solution, the values of phase variables \( \tilde{x}^j \) (oil phase pressure and water saturation) for all grid cells and for all time steps \( j = 1, 2, ..., N \) at current values of the control parameters \( \bar{u} \) are obtained.

- Calculation of functional derivatives at obtained values of measured parameters.

According to known predictive parameters of the forward problem (which can be both phase variables and parameters calculated on their basis), current value of the optimization criterion – the objective function – is computed. It reflects the degree of proximity between calculated and actually measured values of well performance data.

The objective function in a vector form can be represented by the following expression:

\[
J(\bar{u}) = \sum_{j=1}^{N} \left( \tilde{y}^j(\tilde{x}^j(\bar{u}),\bar{u}) - \tilde{Y}^j \right)^T \Omega \left( \tilde{y}^j(\tilde{x}^j(\bar{u}),\bar{u}) - \tilde{Y}^j \right)
\]

(3)

where \( j \) denotes current measurement number at the well, \( N \) is the number of measurements during the study, \( \tilde{y}^j \) and \( \tilde{Y}^j \) are the vectors of calculated (simulated) and actually measured values at the time of \( j \)-th measurement, respectively; \( T \) is the transposition sign. Values of bottomhole pressure, oil flow rate (or well water cut) and water saturation of the near-wellbore zone for the well under study at the measurement time \( j \) are often used as the components of the vectors \( \tilde{y}^j \) and \( \tilde{Y}^j \). Diagonal matrix \( \Omega \) provides normalization of different-sized measurements and sets specific influence of each type of measurement on the value of the objective function. In particular, larger diagonal elements of \( \Omega \) should correspond to quantities measured with smaller errors.

The vector \( \bar{u} \) can be subject to constraints of the form:

\[
\bar{u}_{\text{min}} \leq \bar{u} \leq \bar{u}_{\text{max}}
\]

(4)

To apply an effective gradient (smooth) minimization method, it is necessary to be able to calculate the values of partial derivatives of objective function (3) with respect to the control parameters \( \bar{u} \). Since the solution of the forward problem is carried out numerically, optimal control theory methods are applied to compute the desired derivatives [13]. The main idea is to apply discrete form of the Pontryagin's maximum principle.

Discrete form of the maximum principle avoids the need for direct minimization of the objective function (3), taking into account implicitly specified dependence of \( \tilde{y}^j \) on \( \bar{u} \) (through the solution of the forward problem). Instead, at each iteration of the algorithm, the following sequence of operations is performed [13].
1. Adjoint linear system of equations is stated and solved in order to find auxiliary vectors \( \psi^j \) - values of so-called conjugate function at \( j \)-th time layer:

\[
\left[ \begin{array}{c}
F^j \\
F^j
\end{array} \right] \sigma^j = -F^j \psi^j - \frac{2}{\Delta t^j} \sigma^j, \quad j = N,...,1
\]

where the presence of a vector subscript for any quantity corresponds to a matrix of partial derivatives of this quantity (its components) with respect to corresponding components of the subscript (the vector argument); \( \Delta t^j \) is the size of \( j \)-th time step.

A distinctive feature of system (5) is that its matrix coincides with the transposed matrix of the forward problem (2) at the last iteration for a given time step. In addition, time propagates in the opposite direction (to the natural one). The role of an “initial” condition for the adjoint problem is played by the transversality condition:

\[
\left[ \begin{array}{c}
\psi
\end{array} \right]_{N+1} = 0
\]

2. The obtained values of conjugate functions \( \psi^j \) are further used to calculate derivatives of the objective function with respect to the control parameters:

\[
\nabla J = \nabla T \dot{F}^\psi \psi^j \Delta t^j + \sum_{j=1}^{\infty} \left[ 2 \left( \bar{y}^j \right)^T \Omega \bar{y}^j + \bar{F}^j \psi^j \Delta t^j \right],
\]

where matrix \( \nabla \) takes into account possible perturbation of initial distribution of phase variables due to small changes in control parameters (for example, change in initial water saturation caused by corresponding variation in connate water saturation):

\[
\delta x^0 = \nabla \delta u.
\]

3. The objective function derivatives computed through the formula (7) are later used to calculate a search direction to find the quality criterion minimum according to one of the effective smooth optimization methods. Values of the control parameters (vector \( \bar{u} \)) at the \( \nu+1 \)-th iteration are updated by

\[
\bar{u}^{(\nu+1)} = \bar{u}^{(\nu)} - \beta^{(\nu)} \bar{D}^{(\nu)},
\]

where \( (-\bar{D}^{(\nu)}) \) is the search direction for the objective function minimum; \( \beta^{(\nu)} \) is the step size along the search direction.

The search direction for extremum \( \bar{D}^{(\nu)} \) is calculated in accordance with a selected smooth optimization method. For the class of problems under consideration, among methods requiring calculation of only first derivatives of the objective function with respect to control parameters, quasi-Newtonian methods – the BFGS (Broyden-Fletcher-Goldfarb-Shanno) and the SSVM (Self-Scaling Variable Metric) methods – proved their high convergence rate and robustness [14, 15].

The step size along the selected search direction is chosen to provide the smallest possible value of the objective function at the new point for the control parameters:

\[
\beta^{(\nu)} = \arg \min_\beta J(\bar{u}^{(\nu)} - \beta \bar{D}^{(\nu)})
\]

Exact methods for the one-dimensional search problem (10), such as the golden section method and its analogues, require simulations for the objective function evaluation at a number of successive points. This corresponds to multiple solutions of the forward problem, and therefore it is not computationally efficient. As a more economical alternative, an approximate computational method...
for $\beta^{(v)}$ is used, based on solution of an auxiliary linear boundary value problem, namely, the problem for state variables variations:

$$\bar{F}_{x}^{j} \delta \bar{x}^{j} = -\bar{F}_{g}^{j} \delta \bar{x}^{(j-1)} - \bar{F}_{g}^{j} \bar{D}^{(v)} \quad j = 1, 2, ..., N$$

with initial conditions

$$\delta \bar{x}^{0} = N \bar{D}^{(v)}$$

Here $\delta \bar{x}^{j}$ is the variation (linear part of the increment) of phase variables (pressure, water saturation) in each grid block in response to the variation (small change) of control parameters along the search direction $\bar{D}^{(v)}$.

If we linearize the dependence of $\bar{y}^{j}(\bar{u})$ on $\bar{u}^{(v)}$ along selected search direction $\bar{D}^{(v)}$, then the objective function value (3), taking into account (9), can be approximately represented as a square trinomial with respect to the step size $\beta$. It takes its lowest value at the desired point $\beta^{(v)}$. Hence, the final expression for calculating the step size value takes the form:

$$\beta^{(v)} = \frac{\sum_{j=1}^{N} \left( \bar{y}^{j}(\bar{x}^{(v)}, \bar{u}^{(v)}) - \bar{y}^{j} \right)^{T} \Omega \, \delta \bar{y}^{j}(\bar{D}^{(v)})}{\sum_{j=1}^{N} \delta \bar{y}^{jT}(\bar{D}^{(v)}) \, \Omega \, \delta \bar{y}^{j}(\bar{D}^{(v)})},$$

where $\bar{y}^{j}_{x}$ and $\bar{y}^{j}_{g}$ are the matrices of explicit partial derivatives of $\bar{y}^{j}$ with respect to the phase variables and control parameters, respectively, and variations of calculated well performance data $\delta \bar{y}^{j}$ are found through the variations of control parameters $\delta \bar{u} = \bar{D}^{(v)}$ and phase variables $\delta \bar{x}^{j}$.

- Successively performed computations of the search direction and the step size along it provide a possibility to update the control parameters in an iterative process (confer (9)). Iterations are repeated until a specified stopping criterion is met, reflecting a degree of closeness of the solution found to the required minimum of the objective function.

This description shows in detail the main stages of the inverse problem solution. The apparatus of the optimal control theory turns out to be similar for other problems. Therefore, in the following text, we will focus only on distinctive features of specific well testing technologies and algorithms for their interpretation.

All the technologies considered were tested on synthetic examples. The testing procedure was quite traditional for this class of inverse problems. A set of some values of the control parameters is considered to be the "true" reservoir parameters. On their basis, the forward problem could be solved. Obtained dynamics of well performance data (bottomhole pressure, oil production rate, water saturation of the near-wellbore zone and so on) are perceived as being measured during well testing. Those "measurements" are sometimes made "noisy" by adding random variables with given distribution functions. All those data are used as input data for the inverse problem solution. At this moment, the "true" values of control parameters are being "forgotten".

An arbitrary initial guess is specified to start the iterative process. After the inverse problem solution, and getting a converged solution, it becomes possible to compare the result with the "true" values. As a result of such a procedure, it is possible to test the identifiability of any control through the inverse problem solution and also partially overcome the inevitable property of all inverse problems – namely, to reduce the incorrectness in the sense of existence, uniqueness and stability of the solution. We should say that all the problems considered were carefully tested in this manner and all parameters were found to be fully identifiable. But this is true for the cases considered. It means that parameters could be accurately inferred from observed data if the latter were sufficient in amount.
and quality. Noisy nature of measured data can be overcome with iterative regularization if to choose an iteration number to stop the iterative process in accordance with a special rule [16]. We cannot state, prove any theorem about parameters identifiability, but we can show some practical examples stressing some distinctive features of data measurements during a real well testing procedure. Obtained data play critical role in the quality of inverse problem solution.

3. General approach to determination of RP and reservoir parameters
Traditional approach to well testing involves creation of unidirectional fluid flow to the wellbore in the formation (upper diagram in Fig. 1). New approach to well testing is based on creation of multidirectional two-phase flows in the reservoir. This idea is illustrated by the lower diagram in Fig. 1.

![Figure 1. Schematization of traditional and proposed approaches to oil well testing](image)

The study itself consists of four stages according to the previously described scheme. As a result of this approach implementation, it is possible to pass a wide range of saturations in the near-wellbore area, which forms the basis for determining RP parameters.

When conducting such study, there is a need for sufficiently continuous in time and reliable measurement of bottomhole pressure, oil and water production rates, as well as water flow rate during injection. Another important factor is implementation of at least several evaluations of water saturation in the near wellbore zone at different time moments. Here, well logging methods are very useful. In particular, the method of pulsed neutron-neutron logging during brine slugs injection [12] proved very fruitful.

3.1. RP representation within the inverse problem
Coefficients of relative permeabilities for oil and water as functions of oil (water) saturation are used as control parameters in this study.

Within the framework of inverse problem, relative permeabilities for oil and water could be specified in different ways. It is possible to set RP in the form of parametric dependencies from a certain class, for example:

\[
k_\alpha = C_\alpha (S_\alpha - S_\alpha^*)^{n_\alpha},
\]

\[
k_\alpha = C_{\alpha,2}(S_\alpha - S_\alpha^*)^2 + C_{\alpha,1}(S_\alpha - S_\alpha^*),
\]

where \(k_\alpha\) corresponds to the value of relative permeability for phase \(\alpha\), \(S_\alpha\) is the given phase saturation, \(S_\alpha^*\) is the critical phase saturation. \(n_\alpha\), \(C_{\alpha,1}\) and \(C_{\alpha,2}\) are unknown coefficients, being
subject to identification, together with $S^*_{\alpha}$ and other formation parameters, according to well testing data.

Modern 3D flow simulators employ tabular representation of RP functions. Therefore, it is of practical interest to solve the problem of determining RP parameters in a tabular (piecewise linear) form. In this case, the parameters of RP functions are their values at nodal points. To preserve monotonicity and convexity of RP, additional constraints are imposed on nodal values. The corresponding constraints are taken into account during calculation of search direction and step size within the inverse problem solution [6].

For example, Figs. 2 and 3 demonstrate results of RP identification together with other required parameters for synthetic test problems. Fig. 2 is for a case with RP given in the form of functional dependencies, Fig. 3 – in the tabular form. We can simply judge from those figures that those functions are fully identifiable in cases of enough and accurate measured data.

![Figure 2](image1.png)  
**Figure 2.** RP matching for oil-water system using a polynomial dependence

![Figure 3](image2.png)  
**Figure 3.** RP matching for oil-water system using a piecewise linear interpolation

### 3.2. Technology for reservoir properties, RP parameters and capillary pressure in-situ evaluation for fractured reservoirs

Carbonate reservoirs are usually characterized by complex structure of pore (void) space, and flow through it is often described by a dual-porosity model. In contrast with terrigenous reservoirs, firstly, there are exchange processes between highly conductive fractures and tight matrix. Secondly, capillary imbibition in matrix plays an important role in terms of oil recovery within the phase exchange processes.

Therefore, for the case of a fractured reservoir, parameters that predetermine the processes of fluid exchange between these two flow systems are the most important for production forecast and field development management.

Laboratory studies on cores allow to practically directly measure the desired parameters. However, the scale of heterogeneity and flow processes at core and formation levels are significantly different. For highly fractured rocks, situation is even more complicated because of necessity for nondestructive extraction of a representative rock sample.

Results obtained on the basis of well test data interpretation correspond to the scale of real flow processes in a reservoir. At the same time, traditional well testing is carried out for single-phase flows and it is not capable to carry any information about capillary imbibition.
Peculiar features of the considered technology for carbonate reservoirs and data interpretation algorithm are as follows [17].

Control parameters comprise a number of quantities inherent in the dual-porosity model. For example, value $\sigma$ characterizing intensity of mass transfer between the fracture system and porous matrix blocks. But it exhaustively characterizes only mass transfer for elastic expansion of fluids.

Since capillary forces have a significant effect on the processes of mass transfer between fractures and matrix, parameters of capillary pressure dependences should be also inferred from the inverse problem solution. An example of complete set of estimated parameters after data assimilation is given in Table 1, Figs. 5 and 6. We should stress that all the parameters are identifiable with high level of accuracy.

It is also possible to formulate criteria for assigning a carbonate reservoir to a particular type based on qualitative characteristics manifested during performed simulations of well testing. Such criteria are based on dynamics of bottomhole pressure and phase flow rates at the stage of fluid production after water injection (stage IV).

Fig. 4 presents comparison of water production dynamics for various types of reservoir. As it can be seen from the presented figure, dynamics are significantly different for various types of reservoirs and make it possible to reliably distinguish, based on well testing results, the fractured reservoir with active manifestation of capillary imbibition.

![Figure 4. Dynamics of relative produced water volume](image1)

![Figure 5. Results of RP matching for fractures](image2)

![Figure 6. Results of capillary pressure curve matching for the matrix](image3)
Table 1. Results of inverse problem solution for fractured reservoir

| Parameter                              | Real data | Initial guess (before identification) | Inverse problem solution (after identification) |
|----------------------------------------|-----------|---------------------------------------|-----------------------------------------------|
| Permeability of fractures $k_{fr}$, Darcy | 0.5       | 1                                     | 0.5                                           |
| Skin-zone permeability $k_s$, Darcy    | 0.02      | 0.1                                   | 0.02                                          |
| Skin factor $s$                        | 6.663     | 2.499                                 | 6.663                                         |
| Effective porosity of fractures $m_{ef}^{fr}$, % | 1.6       | 4                                     | 1.6                                           |
| Effective porosity of the matrix $m_{ef}^{m}$, % | 16       | 30                                    | 16                                            |
| Specific surface of porous blocks $\sigma$, cm$^{-2}$ | 8.9$\times10^{-6}$ | 5$\times10^{-4}$ | 8.9$\times10^{-6}$ |

RP in fractures

| Parameter                              | Initial guess (before identification) | Inverse problem solution (after identification) |
|----------------------------------------|---------------------------------------|-----------------------------------------------|
| Exponent for $k_{oil}$ - $n_{oil}$    | 2                                     | 2                                             |
| Oil critical saturation $S_c^{oil}$   | 0.25                                  | 0.25                                          |
| Exponent for $k_{wat}$ - $n_{wat}$    | 2                                     | 2                                             |
| Multiplier for $k_{oil}$ - $C_o$      | 1.777778                              | 4.45752                                       |
| Multiplier for $k_{wat}$ - $C_w$      | 0.64                                  | 0.64                                          |

Capillary pressure in matrix

| Parameter                              | Initial guess (before identification) | Inverse problem solution (after identification) |
|----------------------------------------|---------------------------------------|-----------------------------------------------|
| Multiplier for $P_{cap}$ - $C_{cap}$   | 0.4                                   | 0.4                                           |
| Exponent for $P_{cap}$ - $n_{cap}$     | -3                                    | -3                                            |

For both terrigenous and carbonate reservoirs, an important feature of the developed approach consists in extending the dataset of reservoir parameters obtained for real reservoir conditions.

3.3. Comparison of relative permeabilities evaluated at core level and from special well testing

Several field studies of WT-RP were successfully carried out at various oilfields. Overview of the studies for real reservoirs can be found in [7, 12, 18-20]. Several patents [21, 22] were received. Almost all approaches to evaluating relative permeabilities are focused on determining only critical points of RP functions for two-phase flow and they could not cope with determining the shape of RP functions at reservoir conditions. Our testing procedure potentially permit estimation of the form of RP functions as well as critical saturations.

At the beginning of this paper, we already mentioned the difficulty of upscaling RP parameters from cores to a 3D flow model. Now we will illustrate the corresponding distinction on the basis of well testing data interpretation.

Fig. 7 displays relative permeability curves for oil and water obtained through inverse problem solution based on data collected during injection and production in a two-phase well test. All those curves give the most consistent data with measured values and correspond to the scale of a 3D sector flow model. Symbols in Fig. 7 present core studies results for the same well.
Figure 7. Comparison of RP curves obtained from cores and from data interpretation of a two-phase well test (“cycle 2”)

Oil curve is unified and it coincides with the original core curve. It is scaled taking into account the value of displacement efficiency according to well logging data. This function did not require any adjustment within this study. Water RP curve for the considered second injection cycle is settled below its core analog, but above the curve corresponding to the first injection cycle of the test. This scattering in RP functions conform to increased actual well injectivity observed during the second cycle (with different salinity of injected water). This enhancement may be attributed, among others, to improved conductivity of flow channels or degeneration of oil-water emulsion at increased water salinity, leading to decreased thickness of adsorbed water layers in pores. Water RP curve during production takes higher values associated with observed significant water production during the second cycle.

Several well tests performed on practice [7, 12, 18-20] had their own peculiarities, especially the well setup and arrangements. Specialized wellbore and wellhead setups predetermined possibility for well logging during injection as well as performing different measurements during the study. Unfortunately, we still haven’t managed to perform ideal well testing with collecting all the possible data. Interpretation results after each study characterize their own level of uncertainty, but obtained results were later indirectly proven with further well operation data. But on practice we did not observe full identifiability of all the parameters estimated. We reduced initial level of uncertainty, but could not reach absolute level of reliability of our forecasts.

4. Evaluation of permeability anisotropy based on well testing data

4.1. Vertical self-interference testing technology
Vertical self-interference testing involves a single well, being vertical within the reservoir. But the well should be multifunctional [6]. Namely, two isolated completion intervals should be created (for example, of one meter length) – at the top and bottom of the tested formation. In a cased hole, this can be achieved with appropriate perforation and a single packer. In an open hole – with two packers. One
interval should act as the active one (by means of injection or production, through the annulus or through the tubing), the other one should be the observation interval (with pressure measuring by a pressure gauge, tripped in on the tubing) – see Fig. 8.

For the described testing procedure in case of oil production, the forward problem consists in simulating single-phase flow in an axisymmetric 2D domain taking into account difference in permeability values along horizontal (radial) \( k_r \) and vertical \( k_z \) directions [23]:

\[
\frac{1}{r} \frac{\partial}{\partial r} \left( k_r \frac{\partial p}{\partial r} \right) + \frac{\partial}{\partial z} \left( k_z \frac{\partial p}{\partial z} \right) = \mu \beta^* \frac{\partial p}{\partial t} - 2 g \rho_0 \beta_w k_z \frac{\partial p}{\partial z}. \tag{16}
\]

Here \( k_r \) and \( k_z \) are the values of effective permeability (oil permeability at connate water saturation) [24] in horizontal and vertical directions respectively, \( \mu \) is oil viscosity, \( \beta^* = \beta_o + m_0 \beta_m \) is total reservoir “elastic capacity” (compressibility), \( m_0 \) is effective porosity at initial pressure, \( \beta_o \) and \( \beta_m \) are “elastic capacities” (compressibilities) of oil and effective porous medium (taking into account residual water saturation), respectively; \( \rho_0 \) is oil density at initial pressure.

Boundary conditions to equation (16) correspond to no-flow condition at the upper and lower boundaries of the reservoir as well as at a conventional circular outer boundary. Given flow rate in active well interval is also specified. Initial condition assumes a given (for example, by hydrostatic equilibrium) pressure distribution at the beginning of the test.

Based on implemented numerical algorithm for solving the forward problem (taking into account logarithmic grid along the \( r \) axis), simulations were performed to determine sensitivity zones for two testing options. Namely, for the vertical self-interference testing according to the scheme shown in Fig. 8 and for a well-known testing with several points of pressure measurement in an open hole using a formation tester [25]. In the latter case, vertical separation of active and reactive intervals does not exceed 1.5–2 m, and volume of sampled fluid is very limited.

In our simulations a reservoir grid was subdivided radially into the skin, near and far zones. The length of near zone was varied. Corresponding changes in pressure dynamics on active and reactive intervals were obtained for each case, and testing procedure with different values of permeability (\( k_r \) or \( k_z \)) in the far zone was simulated.
As a result, for a typical set of initial data (see Table 2) the formation tester study is sensitive to changes in \( k_r \) within the 15 meters zone, \( k_z \) – within the 8 meters zone, with strong decrease in sensitivity from first meters apart from the wellbore to the specified distance. And reservoir thickness does not significantly affect this estimate. Taking into account typical schemes for conducting formation tester studies – in open hole before bringing the well into operation, with the presence of a mud filtrate penetration zone – such study is not informative to real value of \( k_z \) in the oil-saturated reservoir.

**Table 2. Initial data for the comparative example**

| Reservoir compressibility, atm\(^{-1}\) | 1.45 \(\times\) 10\(^{-4}\) | Effective porosity at initial pressure, fraction | 0.2 |
|----------------------------------------|------------------|---------------------------------|------|
| Well radius, m                        | 0.1              | Initial reservoir pressure, atm  | 344.5|
| Horizontal permeability \( k_r \), mD | 20               | Reservoir thickness \( h \), m   | 21.5 |
| Vertical permeability \( k_z \), mD    | 5                | Skin factor, fraction           | 1    |
| Flow rate, m\(^3\)/day                | 1.6              | Oil viscosity, cPoise           | 1    |

Similar procedure for assessing sensitivity of the vertical self-interference testing showed that for the reservoir thickness of 35 m sensitivity zone for \( k_z \) covers nearly 31 m, and for \( k_r \) – 250 m and more. And in this case, the well test assumes preliminary well operation (with clearing up the near-wellbore zone) which reduces the impact of the mud filtrate penetration on testing results.

The quality criterion in the problem of vertical self-interference testing is:

\[
J(\bar{u}) = \sum_{j=1}^{M} C_{\text{act}} (P^{j,m}_{\text{act}} - P^{j,c}_{\text{act}})^2 + \sum_{j=1}^{M} C_{\text{react}} (P^{j,m}_{\text{react}} - P^{j,c}_{\text{react}})^2,
\]

where \( M \) is the number of pressure measurements, \( P^j \) is the measured pressure at time \( j \); superscripts \( m \) and \( c \) correspond to the measured and calculated values, and subscripts \( \text{act} \) and \( \text{react} \) – to active and reactive intervals, respectively; \( C_{\text{act}} \) and \( C_{\text{react}} \) are the weighting factors; \( \bar{u} \) is the vector of control parameters represented by the values of \( k_r \) and \( k_z \) in several selected zones of the reservoir (including the skin zone).

![Figure 9. Schematic of reservoir zones in the considered example for vertical self-interference testing](image-url)
| Table 3. Control parameters and their values |
|---------------------------------------------|
| Permeability, mD | Real value | Before identification | After identification |
| $k_{rs}$ | 3 | 10 | 3 |
| $k_{r1}$ | 10 | 30 | 10 |
| $k_{r2}$ | 15 | 35 | 15 |
| $k_z$ (not varied) | 2 | 2 | 2 |
| $k_z$ | 5 | 10 | 5 |
| $k_{z2}$ (not varied) | 10 | 10 | 10 |

![Figure 10. Pressure dynamics at the reacting interval in the considered example](image)

**4.2. 3D interference testing for horizontal wells**

One of the consequences of the EPS concept consists in a new technology of vertical-lateral waterflooding [6]. Its designing and implementation led to necessity of a 3D interference test method on the basis of horizontal wells to clarify a degree of reservoir connectivity along the vertical axis. A scheme of the test for a typical development pattern is shown in Fig. 11.

The 3D interference test was implemented at one of oil fields in Western Siberia. The pilot plot (see Fig. 11) consisted of two horizontal wells – one producer (reacting) at the top of formation and one injector (active) – at the bottom of formation [26].
Before drilling a horizontal wellbore, a pilot wellbore was initially drilled in each well and logging measurements were performed. 100% coring was also undertaken in one pilot for target formation interval. Core studies have clearly shown the presence of thin low-permeability layers in the reservoir cross-section which could not be detected by logging data.

A 3D sector flow model was created for the testing results interpretation. Due to absence of a reliable 3D geological model, a layered heterogeneous model was used. Layer properties (including initial values of permeability) in the model were taken based on well logging results in the pilot wellbore of the producer.

According to the EPS concept [24], all layers in the model were made permeable. For layers identified as non-pay by logging data, initial value of horizontal permeability was set to 0.1 mD, and permeability of other layers was computed through a porosity-permeability correlation. Simulations on the sector flow model were performed in two-phase (oil-water) statement due to high water cut in this area as a result of previous development.

Two parameters were considered as controls. Namely, a single multiplier for permeability of all layers in all coordinate directions and a multiplier for vertical permeability, with options – for all layers in the model or only for low-permeable (former “non-pay”) layers. These two multipliers highly affect integral permeability anisotropy in the model.

Fig. 12 shows a comparison of calculated (after data assimilation) and actual pressure curves in the reacting well during the main stage of interference testing, when water injection into the active well took place. Here, the trend associated with pressure redistribution due to other wells stopping in the area was excluded from the actual pressure dynamics. Subsequently, simulation was carried out taking into account proper operation of other wells and it confirmed feasibility of obtained parameter values.

Weighted average (with respect to layer thicknesses) permeability in horizontal direction was found equal to 12.9 mD, and in vertical direction – 1.6 mD; ratio of horizontal to vertical permeability was equal to 8.1.
Figure 12. Simulated and actual pressure dynamics in the reacting well

Such type of 3D interference testing is required mainly during implementation of the vertical-lateral waterflooding. Another case for realization of 3D interference testing is associated with massive oil deposits, provided that completion intervals of tested wells are separated both vertically and laterally.

4.3. 3D interference testing based on vertical wells

The scheme of active and reactive wells presented in Fig. 13 is an example of the corresponding technology for 3D interference testing [6, 27, 28]. Reacting wells are distributed areally around the active well, and their completed intervals are located at different depths.

Figure 13. Scheme of the 3D interference test: well 7 (B) – active, wells 1-6 (P) – reacting. Numbers are distances in meters (just for example)
The forward problem is solved numerically. It is formulated for the 3D single-phase case, taking into account full matrix of the effective permeability tensor $K$:

$$
\text{div} \left( \frac{\rho(P)}{\mu(P)} K (\nabla P + \rho(P) g \nabla h) \right) = \frac{\partial (m(P) \rho(P))}{\partial t} + Q(t),
$$

(18)

where dependencies of oil density and viscosity $\rho, \mu$ and effective porosity $m$ on pressure $P$ are taken into account, $h$ is the elevation depth of a given point, $Q(t)$ is the intensity of sources / sinks associated with the active well operation. Initial and boundary conditions correspond to a given initial pressure distribution and no flows across external boundaries of selected model area, respectively.

The inverse problem, as for previous technologies, is solved with the methods of optimal control theory. Minimized quality criterion is the following functional:

$$
J(\bar{u}) = \sum_{j=1}^{M} \sum_{w=1}^{N} c (p_{w,j}^c - p_{w,j}^m)^2
$$

(19)

Here $j$ is the serial number of a measurement, $M$ is the number of measurement moments, $N$ is the number of wells with pressure measurements, $c$ are weighting coefficients, $\bar{u}$ is a vector of control parameters, $p_{w,j}^c, p_{w,j}^m$ are respectively the calculated and measured values of bottomhole pressure at the moment $j$ in well $w$.

Results of algorithm testing for solving the inverse problem on synthetic examples have shown the possibility of successful identification of all 6 components of the full symmetric matrix of the permeability tensor together with volumetric reservoir parameters (porosity) [27, 28]. In other words, all control parameters are fully identifiable in case of presence of accurate and abundant measurements.

Field experiment on 3D interference testing was carried out at one of the fields in Russia. Reservoir refers to complex reef carbonates and possesses significant oil-saturated thickness. A distinctive feature of the undertaken testing consisted in a perimeter injection well (14-PS) serving as an active well, and several producing wells (126, 2, 121 and 13) serving as reactive wells [6, 27, 28]. Well locations in this study are shown in Fig. 14. Fig. 15 gives a reservoir cross-section with marked well completion intervals.

Figure 14. Area of the interference test (boundaries marked in red) and directions of the coordinate axes adopted in interpretation of the 3D test results
As an initial guess for the inverse problem solution, results of interference test interpretation by traditional method were taken, i.e. based on independent consideration of each pair of active-reactive wells. This made it possible, together with geological model data, to obtain estimates of effective permeabilities (along x and y axes) and effective porosity for drainage areas of each well. Initial effective permeability values along z axis were taken equal to 0.1 of permeability along x axis.

Mathematical experiments in relation to existing sources of information and specifics of the study have clearly shown that it is impossible to evaluate all components of full matrix of the permeability tensor due to actual multiphase nature of flows in the reservoir and lack of reliable information about quantity and tracing of tectonic faults and their conductivity. On the other hand, since the sources of original measurements were 5 wells participating in the 3D interference testing, the 3D sector model was subdivided into 5 zones. The inverse problem control parameters involved principal values of permeability $k_{xx}$, $k_{yy}$, $k_{zz}$ and effective porosity $m_0$ in each of the 5 zones. Other options for splitting the 3D sector model were also considered.

Figs. 16 and 17 depict examples of measured and simulated bottomhole pressure dynamics for one of the reactive wells and the active well. We can note that a satisfactory match of calculated and actual dynamics of the bottomhole pressure has been achieved as a result of iterative procedure of data assimilation. In this case, the final value of objective function (19) turned out to be almost 130 times less than its initial value. Calculated values for the well 126 are the closest to the measured bottomhole pressures. The most distant from the true pressure values are the results for wells 121 and 14PS. This can be partly explained by the multiphase flow in the real test. Existing discrepancies between actual and calculated bottomhole pressures are associated with insufficient reliability of the original geological model.

Results of the inverse problem solution are summarized in Table. 4.

Figure 15. Scheme of well completions in the test
Figure 16. Bottomhole pressure dynamics for reactive well 126

Figure 17. Bottomhole pressure dynamics for the active well 14PS.

Table 4. Control parameter values

| Control parameters | Before data assimilation | After data assimilation |
|--------------------|--------------------------|-------------------------|
| $k_{xx}$, mD       |                          |                         |
| Zone 1 (well 2)    | 1080                     | 140.21                  |
| Zone 2 (well 13)   | 4880                     | 127.58                  |
| Zone 3 (well 121)  | 3590                     | 183.88                  |
| Zone 4 (well 126)  | 1540                     | 397.54                  |
| Zone 5 (well 14-PS)| 23                       | 1571.88                 |
| $k_{yy}$, mD       |                          |                         |
| Zone 1 (well 2)    | 1080                     | 34.11                   |
| Zone 2 (well 13)   | 4880                     | 618.98                  |
| Zone 3 (well 121)  | 3590                     | 47.89                   |
| Zone 4 (well 126)  | 1540                     | 241.27                  |
| Zone 5 (well 14-PS)| 23                       | 2.67                    |
| $k_{zz}$, mD       |                          |                         |
| Zone 1 (well 2)    | 108                       | 1424.04                 |
| Zone 2 (well 13)   | 488                       | 34.83                   |
| Zone 3 (well 121)  | 359                       | 5321.59                 |
| Zone 4 (well 126)  | 154                       | 1516.42                 |
| Zone 5 (well 14-PS)| 2.3                       | 770.59                  |
| $m_0$              |                          |                         |
| Zone 1 (well 2)    | 0.1                       | 0.123                   |
| Zone 2 (well 13)   | 0.15                      | 0.0098                  |
| Zone 3 (well 121)  | 0.1                       | 0.4                     |
| Zone 4 (well 126)  | 0.1                       | 0.014                   |
| Zone 5 (well 14-PS)| 0.15                      | 0.01                    |

It can be clearly seen from Table 4 that initial values of reservoir parameters underwent serious modification. Namely, permeabilities of each zone in the final solution are significantly different along the three main directions. This is associated with peculiarities of complex carbonate sediments with developed fractures. Besides, non-physical values of porosity in some zones attract serious attention. Those values could be explained by imperfection of underlying 3D geological model. The fact that the studied area is located in a waterflooded zone also influenced the obtained solution.
5. Conclusions
Well testing is a very popular way of getting various information regarding reservoir properties. Its interpretation is getting more and more sophisticated. A wide range of well testing techniques with data interpretation algorithms and example cases was considered in this paper. All inverse problems are fully identifiable if reliable, accurate, long-term and diverse data are being measured during well testing. It seems very fruitful and promising to complicate well testing with well logging and assimilate both types of measured data simultaneously.

Acknowledgements
The paper was prepared as part of the State Research Contract of OGRI RAS (topic "Scientific substantiation of new environmentally friendly development technologies for hydrocarbons deposits in difficult mining and geological conditions on the basis of 3D computer experiments", No. AAAA-A19-119022090096-5).

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