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## EDITORIAL

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## Problems of exploration and development modeling of oil fields

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**Abstract.** The article shows the construction features of geological and geological-hydrodynamic models for solving various problems: prospecting, exploration, development and design of enhanced oil recovery (EOR) methods application. Depending on the tasks assigned, the simplest models should gradually and continuously become more complex. When constructing geological models, it is necessary to take into account all the geological reserves in the subsoil of the object under consideration, regardless of whether they can be extracted today or not. In this case, much attention should be paid to the so-called tight (in the modern sense) sections between the layers and the study of their role in filtration processes. In the construction of geological and filtration models for deposits with hard-to-recover oil reserves, it is necessary to study the details of the geological structure and especially the fracturing, since these details have a determining effect on the efficiency of the development and application of the EOR. Essentially new approaches to modeling are presented.

**Keywords:** hard-to-recover reserves, geological and recoverable reserves, methods for increasing oil recovery, processing of bottomhole well zones, geological and geological-hydrodynamic models

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The specific feature of designing each field (as opposed to the design of any other facilities and structures) is the specificity of each field. In the world there are no fields identical in geological structure. Therefore, any new technologies applied on any fields, which turned out to be successful in certain geological conditions, tend to become ineffective in other geological conditions in other fields. To design new technologies in new fields, large studies are needed to research the features of the geological structure (at macro, micro and nano levels) and the compatibility of these technologies with the geological structure of the deposits. This requires efforts of specialists from universities, research centers, industry, sufficient time and resources.

The process and organization of creating oilfield models depend on the goals set for the designers. These goals can be combined in the following areas:

- Exploration and preparation for the development of fields;
- Design and development of oil fields by conventional methods;
- Modeling the exploitation of oil fields using (as main) tertiary methods of development (thermal, gas) from the very beginning of the development of the facility;

- Modeling of various methods and technologies for increasing the efficiency of oil field development (oil recovery enhancement, bottomhole zone treatment, hydraulic fracturing, drilling of horizontal wells, lateral wells, multihole wells, drilling of additional wells, forced liquid withdrawal, etc.);

- Modeling of the previously unaccounted for reserves of deposits in tight (ultralow-permeable) layers in exploited fields;

- Modeling of oil reservoir reformation (regeneration) processes in the fourth stage of field development and hydrocarbon feeding from the depths of the Earth's interior.

The expansion of the modeling objectives is a result of new ideas about the staging of the development of oil fields. Earlier we also adhered to the allocation of four stages of development of oil deposits. But at the same time, the IV stage of development (on the significance in the formation of high oil recovery values and the duration of development terms) was understood quite differently (Muslimov, 2003; 2016). But at the present time it is obvious that it is necessary, first of all, for large fields to allocate also the V stage of development, in which the oil reserves will be exploited that were not previously accounted either in the official oil balances or in the accepted development projects (reserves in tight strata, previously stationary reserves in the exploited objects).

The main question is what to invest in the concept of a geological model?

S.N. Zakirov (Zakirov et al., 2009) quite rightly considers the very ideology of building models wrong. In his opinion, the methodological documents prescribe “non-reservoirs” not to include into 3D geological models. That is, all (almost all) created 3D geological models in the country are defective, as in them the real geology of fields is artificially distorted (Muslimov, 2014; Muslimov et al., 1994).

In connection with the foregoing, there is a need to reassess the geological resources of oil, since balance and recoverable reserves, in the old, established understanding, leave behind substandard reserves, and they, according to preliminary estimates, may amount to 15-20% of approved ones.

It seems advisable to develop a methodology for calculating geological reserves, taking into account the tremendous progress in the West in the field of geological research and the available experience in extracting hydrocarbons from tight rocks (or shales). In that case, the current “substandard” reserves in the overall balance sheet will be the object of the oil company activity in carrying out research and development projects and searching for ways to extract them.

At the same time, it is more understandable for all specialists to suggest that all geological reserves (including “substandard reservoirs” in carbonate deposits (Muslimov et al., 1998; Volkov et al., 2007) should be considered. Deposits with terrigenous strata are more difficult to conceive, but such a model construction can be more acceptable if we study the structure of the so-called tight reservoirs between the strata and their role in the filtration processes. It can be significant.

The estimates made by the authors (Volkov et al., 2000) suggest that vertical flows in the development of a layered heterogeneous reservoir consisting of layers, represented by different types of reservoirs, can play a significant role. Interlayers can be produced from them, which, when tested directly through wells, give no oil at all or only non-industrial inflows.

The fundamental problems include the need to build a model based on the concept of effective pore space (Zakirov et al., 2009). At the same time, data on reservoir properties should be obtained from real cores with real content of associated water. According to the concept of effective pore space, petrophysical dependencies need to be built based on realistic coefficients of effective permeability and effective porosity, because the degree of reliability of petrophysical dependencies within the framework of the effective pore space is significantly higher than in the concept of absolute pore space. Then it is obvious that the reliability of the logging data for the construction of 3D models will become essential.

Also, special attention should be paid to the determination of the real displacement efficiency  $K_d$  – the most important parameter for evaluating the

effectiveness of applied and projected development systems and the efficiency of geological and technical measures. The experience of long-term development of fields shows that in developed areas,  $K_d$  is higher than that determined by laboratory studies with the so-called endless flushing. Consequently, in these areas, the coverage ratio of  $K_c$  will be lower and should be increased by compacting wells pattern and improving the impact on the reservoir. This is a cardinal promising conclusion for the design of measures to increase oil recovery factor (Zakirov et al., 2009; Muslimov, 2012).

Thus, when constructing geological models of oil deposits, it is necessary to:

- study the volume distribution for all models not only balance, but all geological reserves of oil, differentiating the latter into moving, slow-moving and immobile;

- fix the location and determine the reservoir properties of not only the oil-saturated, but also all “tight” and water-saturated interlayers, between the impermeable roof and bottom of the single hydrodynamic system. The system includes the considered deposit or considered set of oil layers (Dyachuk, Knyazeva, 2016).

This fundamentally new approach to geological modeling requires a lot of work to create completely new geological models that most fully take into account the geological basis of the formation of oil deposits.

Models for exploration and preparation for development should be based on the use of primary data from field geophysical measurements, logging data and laboratory studies. All these data should be used in the drafting pilot projects for testing recommended future development technologies.

Design should be based on the classification of fields with active oil reserves (usually large and supergiant), inefficient fields with reserves difficult to recover (mainly medium and small) (Muslimov, 2003), also taking into account the modern classification of oil deposits (Dyachuk, 2015).

For fields that are in the later stages of development, a revision of the entire geological model is necessary, taking into account successful development of deposits in the West with low-permeability reservoirs and technogenic changes in reservoir parameters during long-term operation (Muslimov, 2012), and a synthesis of development experience (as supergiant Romashkino field development shows) is needed. Here it is necessary to radically change the ideology of building a geological model, in which all the oil reserves of an operating facility should be considered, including conditioned and substandard rocks. This is due to new technologies for developing reserves in the final development period (Zakirov et al., 2009; Muslimov, 2012; Dyachuk, Knyazeva, 2016).

At the same time, at the beginning of operation, usually each object of independent development tend

to be distinguished into a large number of layers with different geological characteristics, each of which usually serves as an object of independent impact. Then at the late (IV) stage of development previously separated layers of an operational object must be combined to operate the facility in forced modes and high water cut of wells to increase the recovery efficiency.

During this period, it is envisaged to use the already developed methods of enhanced oil recovery (mainly physicochemical and physical, then forced fluid withdrawal), and further to study the processes of reformation of deposits in the long-term operation and to use them in modeling the current production and oil recovery factor (Dyachuk, 2015; Plotnikova et al., 2013), further modeling of the processes of recharge of exploited hydrocarbon deposits from the depths (Belyaev et al., 2002; Kudinov, Suchkov, 1998).

However, this does not limit the potential for the further increase in resources of the supergiant Romashkino field. To increase it, it is necessary to conduct a large amount of research (including fundamental research). These works should be carried out in the following directions:

- study of tight sections between productive strata of traditionally allocated operational facilities (porosity, permeability, oil saturation, particle size distribution, and other parameters characterizing the geological structure features of tight rocks in sediments of terrigenous and carbonate complexes, lower and middle Carboniferous);
- study of tight rocks of carbonate Devonian, Lower, Middle and Upper Carboniferous deposits for the identification of promising objects for possible future use as objects of exploitation using the latest research and mining technologies;
- determining, by the indicated groups of deposits, methods of research that can be used to attribute their possible resources to the balance reserves, outline possible ways of their development, evaluate the recovery factor and recoverable reserves (in ultra-low-permeability formations);
- study of the hydrocarbon potential of the ultra-viscous oil and natural bitumen of the Permian deposits of the field, the search for new ways to develop reserves in unconventional hydrocarbon deposits.

It is necessary to start modeling the processes of reformation (regeneration) of oil deposits and supplying them with hydrocarbons from the depths of the Earth's interior, while modeling of exploration and development of tight (ultra-low-permeable) formations is already needed.

The features of modeling geological structure and oil displacement processes in small and medium-sized fields are determined by the specifics of their development strategy.

The experience of developing small and medium-sized

fields allows determining a different (than large and giant fields) development strategy. Highly productive development of these fields should be phased. But at the same time, it is necessary to take into account the peculiarities of the geological structure of these fields. While in high-yield fields there is a large proportion of active oil reserves, reaching up to 65-80% of all reserves, then in low-productive fields, as a rule, it is no more than 10%. In the first case, their high proportion provides a quick exit to the maximum level of oil production and a relatively long retention period (before extraction about 50% of initially recoverable reserves), in the second case such dynamics of oil production is not possible. Here it is immediately necessary to apply new enhanced oil recovery methods and bottomhole zone treatment to ensure an acceptable level of production and its subsequent retention. The stage of development of the field here is not due to the consistent development of different levels of oil, but mainly the phased introduction of various components (elements) of the development system.

It should be noted that the role of cracks in the displacement of oil in the development process is crucial not only for cavernous fractures, but also for granular

reservoirs. Indeed, macro- and microcracks are present in almost the vast majority of reservoir rocks. They play a major role in filtering processes. Moreover, in practice the case prevails when there is an inflow of oil into the cracks from the reservoir matrix as a result of the creation of different-variable pressure drops between the cracks and the main part of the rock in the process of development. This occurs during unsteady waterflooding and pulsed operation of production wells. Fracturing in carbonate reservoirs plays an especially important role.

The peculiarity of hard-to-recover reserves is that the seemingly insignificant features of the geological structure details which, in most cases, we either do not know or do not focus on them, have a decisive effect on the efficiency of their development. Let us explain this with some examples.

Macro- and microheterogeneous carbonate formations contain inclusions of other minerals: gypsum, calcite, anhydrite, clays, pyrite, as well as bitumen and various metal oxides. The combined filtration of oil and water, or oil, water and gas, is greatly influenced by the composition of the rocks and the physicochemical properties of these phases, as well as the fractured rock itself and the degree of crack opening.

Thus, the presence of fracturing in the roof of the Kizelovsky deposit of the Tavel'sky field according to the R.Kh. Zakirov 1.5-1.8 times increases the flow rate of oil, and therefore oil recovery factor, and the flow rate of oil directly depends on the opened thickness of the formation.

According to the Bashkirian layer of the Akansky

field, represented by extremely heterogeneous carbonate reservoirs, the use of waterflooding methods (including in the treatment with nanofluid) turned out to be ineffective. This is due to the presence of cracks of different origin. Here, against the background of small cracks of various generation, larger vertical and sub-vertical cracks of tectonic origin are also present. These structural features of the deposit were recently identified by I.N. Plotnikova and V.P. Morozov. Naturally, under these conditions, any liquid to displace oil from carbonates will not work until it is possible to heal large tectonic cracks. For this we need completely new innovative technologies. L.K. Altunina tried to implement this task. After a long period of original research, the reasons for the inefficiency of conventional flooding methods became clear. The task is extremely complicated - it is necessary to heal powerful vertical tectonic fractures and make small fractures of deposits to take water.

In the Serpukhovian-Bashkirian deposits of the Romashkino field (deposits 301-302), as established by D.V. Guskov, within the limits of positive local structures, compression occurs in the basement part of the formation, which hinders the rate of watercut of the wells with bottom water. Anhydrous periods in such areas are maximal, which allows recommending these areas of the deposit as the most promising for laying producing wells, killing the second wellbore and carrying out various geological and technical measures in order to obtain oil flows with low watercut. Negative local complications are zones of loosening reservoirs in the area of oil-water contact, leading to intensive watering, therefore, it is necessary to produce reserves of these sections in a part load mode.

Today, the issues of studying the directions and development of fractured zones are a priority task for detailed geological studies. Modern geological models should designate these details in order for designers to most effectively determine the location of injection wells and the position of tracks in horizontal wells. Depending on the thickness and reservoir properties of the formations, injection wells can be located either across, along or diagonally to the development of fractured zones. With such geological models, designers can purposefully force cracks to increase oil displacement from the main matrix of the rock (for example, using cyclic flooding).

Knowledge of such details of the projected objects, embedded in the geological models, obviously, will suit the designers in the preparation of technological schemes and field development projects. But they are not enough for the purposeful design of the use of enhanced oil recovery methods in fields. It can be designed as in new fields, the development of which from the very beginning is projected using new development technologies in non-flooding regimes (the introduction of thermal

development methods in fields with high-pressure oil and steam, gas and water-gas methods at fields with low-permeability and ultra-low-permeability formations), and at fields developed with the use of flooding. In the latter, the enhanced oil recovery factors should improve the efficiency of developing reserves and increase oil recovery. For such a design, subtle, more detailed, advanced geological models should be applied.

According to the operating experience of unproductive fields of Tatarstan, the following strategy for their development is recommended:

1. Drilling of initially large well pattern (12-16 ha);
2. Clarification of the geological structure of the deposit with the construction of a geological model with fundamentally new approaches that take into account the fundamental laws of geology, i.e. with the inclusion in the object of the entire strata of the oil-bearing floor (from the roof to the bottom of the selected object of operation);
3. Gradual, incremental infill of well pattern (up to 8, then 4 and 2.5-3 ha/well).

At all these stages, a new refined model of the geological structure of the object is being built, taking into account the new grid of wells.

4. At each stage, geological models must be turned into geological and hydrodynamic, taking into account the organization of the waterflood system with its gradual improvement, ensuring the development of deposits at optimum reservoir and downhole pressures. At the same time, it is necessary to take into account the use of impact methods with their gradual complication:

- complex development technologies worked out in Tatarstan of low-permeability and clay terrigenous reservoirs and high-viscosity oils, complex technologies for the development of deposits in carbonate reservoirs, in less permeable formations – hydraulic fracturing;

- the use of light thermal enhanced oil recovery methods and bottomhole treatment (TGHV, PPH, VPTHO, PTOS, electrical heating, PZP, etc.) (Muslimov, 2012);

- injection of hot (or heated) water into the formation, including refined with various chemicals. Here it is necessary for each object to build the oil viscosity-temperature curve, which will help determine the optimal temperature of the pumped agent.

5. After infilling the wells pattern to the optimum value for classical thermal enhanced oil recovery methods (PTV, steam gas, in-situ combustion), update the geological-hydrodynamic model obtained after the above actions. Further design should be based on it.

The problem of linking new development technologies to the geological conditions of the designed field (their compatibility and adequacy) is solved by innovative design of development systems.

Innovative design is the lever that can control the

development of a field (from additional exploration to enhanced oil recovery). Firstly, this includes all the necessary research on the development problems of each field in accordance with its specificity. Under normal conditions, this requires performing dozens of different topics. Secondly, such a project after official approval acquires the force of law and obliges the oil company to execute it.

In this connection, Yu.A. Volkov recommends starting the drafting of the project with the analysis of the simplest models and complicating their structure gradually, as necessary, i.e. introducing into practice a multi-model approach to the creation and improvement of oil recovery technologies, representing the “new design philosophy” of oil field development.

The ways to solve these problems are the essence of the cluster approach to the development of the new generation standard “the regulation of innovative design development and optimization of the development of hydrocarbon reserves with their continuous replenishment”. In contrast to the standard recommended by the Central Committee of Reserves for mass design, it may also include conducting pilot works to test new technologies at a particular field in specific geological conditions.

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## Digital field

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**Abstract.** The paper presents the developed computational technologies that participate in a complex of programs for creating a digital model of an operating field. Linear methods of processing the areal systems of seismic observations, as well as algorithms for determining the electromagnetic parameters of the near wellbore space for a horizontally layered medium, are developed. A computational technology was developed that allows real-time monitoring of well production rate, gas factor and water cut for additional thermodynamic parameters of wells. On the basis of this technology, methods are implemented to maximize the production of the existing field, taking into account the diameter of the pipelines, the intensity of production, etc. The algorithms for determining the reservoir field filtration coefficient from the pressure data specified in the injection and production wells have been developed, on the basis of which the drilling of new additional injection and production wells has been optimized.

**Keywords:** inverse problems, computational methods, filtration, logging, seismic survey, high-performance computing

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### Processing of seismic data of areal measurement systems

At present, thanks to areal observation systems, it was possible to create a fundamentally new method for solving three-dimensional inverse problems, in which the following is used: the three-dimensional analogue of the M.G. Krein equation (Kabanikhin, 1989; Kabanikhin et al., 2004; Kabanikhin, Shishlenin, 2011), parallel computing on high-performance clusters, Monte-Carlo methods (Kabanikhin et al., 2015b; Kabanikhin et al., 2015c), super fast processing algorithms for block-Toeplitz matrix of large dimensions (Kabanikhin et al., 2015a).

The main problem of studying three-dimensional elastic media is the large size of the region; even for a section of 2 km×2 km×2 km, the solution of the direct seismic survey problem with a resolution of 1 meter can take up to 150 hours on 80 cores of a single node of a computing cluster. And if we take into account that most modern methods for solving inverse problems are based on iterative procedures, then even the number of operations required to perform several iterations can lead to uncontrollable errors. This circumstance is

complicated by the strong incorrectness of the inverse problems, which consists in the nonuniqueness of the solution, as well as in the instability, which greatly increases with depth.

Previously, an algorithm was proposed for the numerical solution of the inverse problem for systems of equations of the hyperbolic type (acoustics, Maxwell, Lamé equations) in three-dimensional space with additional information on a part of the half-plane (areal observation system) (Kabanikhin, Shishlenin, 2011). The basic idea is to apply the projection method with the subsequent reduction of the nonlinear inverse problem to a multiparametric family of linear integral equations (a multidimensional analog of M.G. Krein equation) (Kabanikhin, 1989).

Let us consider the inverse problem of determining velocity of the medium:

$$c^{-2}(x, y)u_{tt}^{(k)} = \Delta u^{(k)}, \quad x \in R, \quad y \in R, \quad t > 0, \quad k = 0, \pm 1, \pm 2, \dots$$

$$u^{(k)}(x, y, 0) = 0; \quad u_t^{(k)}(x, y, 0) = e^{iky} \cdot \delta(x).$$

using additional information.

$$u^{(k)}(0, y, t) = f^{(k)}(y, t), \quad u_x^{(k)}(0, y, t) = 0, \quad k = 0, \pm 1, \pm 2, \dots$$

Let  $\tau(x, y)$  be a solution to the Eicolnal equation:

$$\tau_x^2 + \tau_y^2 = \frac{1}{c^2(x, y)}, \quad x > 0, \quad y \in R;$$

$$\tau(0, y) = 0, \quad \tau_x(0, y) = \frac{1}{c(0, y)}, \quad y \in R.$$

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We introduce new variables and functions:

$$z = \tau(x, y), \quad y = y.$$

$$v^{(k)}(z, y, t) = u^{(k)}(x, y, t), \quad b(z, y) = c(x, y).$$

Then the nonlinear coefficient inverse problem can be reduced to a family of integral equations (a multidimensional analog of M.G. Krein equation):

$$\sum_m S^m(z, y) f_m^k(t-z) + w^{(k)}(z, y, t) +$$

$$+ \sum_m \int_{-z}^z f_m^k(t-s) w^{(m)}(z, y, s) ds = 0,$$

$$|t| < z, \quad k = 0, \pm 1, \pm 2, \dots$$

Here the function  $w^{(m)}(z, y, t)$  has the following form:

$$w^{(m)}(z, y, t) = S^{(m)}(z, y) \delta(z-t) + Q^{(m)}(z, y) \theta(z-t) +$$

$$+ Q^{(m)}(z, y) \theta(z-t) + \tilde{w}^{(m)}(z, y, t).$$

M.G. Krein equation should be supplemented with the following tasks:

$$\begin{cases} 2S_z^{(m)} + qS_y^{(m)} + pS^{(m)} = 0, & z > 0, y \in R, \\ S^{(m)}(0, y) = \frac{1}{2} e^{imy} \end{cases}$$

$$\begin{cases} 2Q_{zz}^{(m)} = S_{zz}^{(m)} - [qQ_y^{(m)} + b^2 S_{yy}^{(m)} + pQ^{(m)}], & z > 0, y \in R, \\ Q^{(m)}(0, y) = 0 \end{cases}$$

Here

$$q(z, y) = 2b^2(z, y)\tau_y, \quad p(z, y) = b^2(z, y)(\tau_{xx} + \tau_{zz}),$$

$$b(z, y) = c(x, y).$$

### Determination of parameters of existing wells using standard pressure and temperature sensors

Extraction of oil from wells is carried out either due to natural spouting under the action of reservoir pressure, or by using one of the mechanized methods of lifting liquid. usually in the initial stage of development, the fountain production is in operation, and as the flow-out weakens, the well is transferred to the mechanized method. One of the important tasks of diagnosing the state of a well is the operative determination of changes in well flow rate, gas factor and water cut (Kabanikhin et al., 2011). Earlier, an algorithm was developed for estimating these parameters, based on a numerical simulation of a direct problem consisting in determining the pressure and temperature along the wellhead of a vertical well from a given temperature and pressure at the bottom of the well. The methods for calculating the direct problem for the acting well are based on solving the heat and mass transfer equations. To calculate the thermophysical properties of the water-oil-gas mixture, data are used on the standard characteristics and composition of the oil-gas mixture, empirical correlations, diameter and

slope of the well, flow patterns (bubble, cork, ring) and others. The distribution of pressure and temperature in the wellbore, taking into account the structure of the flow and the depth of degassing. Differential heat and mass transfer equations are solved numerically from the bottom to the wellhead. In the inverse problem, it is required to determine the flow rate, gas factor and water cut according to the pressure and temperature measured at the wellhead. The works (Ryazantsev et al., 2013; Kabanikhin et al., 2011) show developed algorithms for solving direct and inverse problems in the case where pressure and temperature measurements are made at a certain depth. In this paper, it is shown that this algorithm can be applied for the well to be used in the case when pressure and temperature are measured on the surface (in the wellhead) of the well. The importance of solving direct and inverse problems in a well is determined by the fact that at present only about 100 thousand wells are operated in Russia. Installation of special equipment that allows to carry out permanent well operation monitoring is complicated and expensive. Monitoring and computational technology were implemented using sensors included in the standard set of submersible pump telemetry and additional measurements of pressure and temperature on the surface in real time. Based on the developed algorithms, a computational technology has been implemented, which allows to maximize the production of the existing field taking into account the diameter of pipelines, the intensity of production, etc.

### Determination of the reservoir filtration of the existing field by pressure sensors installed in wells

One of the important tasks of the existing field is to determine reservoir parameters by measuring the pressure inside the wells of the field. On the basis of a mathematical model of the diffusion equation, the inverse problem is solved to determine the filtration coefficient according to the pressure given in the injection and production wells. The problem is reduced to solving a multidimensional coefficient inverse problem for the diffusion equation using data measured in a discrete set of points (Kabanikhin, Shishlenin, 2018).

The problem of optimizing the placement of additional injection and production wells was also solved, taking into account the data obtained in solving the inverse problem.

### Determination of electromagnetic parameters of the near-wellbore space

A computational technology has been developed that makes it possible to determine the electromagnetic parameters of the near-well space in the case of a horizontally layered medium in the case of one source and two receivers of the reflected signal. The formulas

obtained at the interface between the media (on the basis of conservation laws) guarantee the physicality of the results obtained and the adequacy of solving the coefficient inverse problem (Romanov et al., 2010; Epov et al., 2011a; Epov et al., 2011b; Epov et al., 2011c).

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## Scientific engineering as the basis of modeling processes in field development

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**Abstract.** Three characteristic examples of the use of scientific engineering approaches for managing the technological processes of reservoir modeling at different hierarchical levels are presented in the article.

The first example demonstrates the application of the spectral approach for modeling geophysical fields – the available log data is decomposed from the spectrum of Legendre polynomials, after which a stochastic field of the expansion coefficients is constructed. The results obtained by this method of realizing geophysical fields correspond to real data in a wider area of modeling than in classical methods. The speed of building models also increases due to the convenience of parallelization.

The second example demonstrates the use of the source method to optimize the transfer of wells into injection. A flow rate of each well is found by simulating the wells in the development system as linear sources or sinks and recording the resulting system of equations for the flows at each time. According to the optimum of discounted extraction, there is an economically efficient time for well development.

The third example demonstrates the application of the theory of dimensions to the problem of hydraulic fracturing modeling to determine the significance of certain parameters for the design of fracturing. By measuring the dependence of the fracture length on the injection volume, we obtain an empirical formula for the fracture length from its parameters, which determines the level of their significance.

**Keywords:** geological modeling; geostatistics; geomechanics; hydraulic fracturing; hydrodynamic modeling; source method

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The tasks of monitoring and controlling technological processes in field development often lead to the need to simulate geophysical fields, processes associated with filtration in the reservoir and movement through pipes of multiphase mixtures, geomechanical tasks during drilling and during hydraulic fracturing, and many others. Traditionally, the description of oil and gas production processes is carried out on the basis of differential equations of motion of liquids and gases in porous media and pipes. However, this approach does not allow one to describe many of the essential properties of the formation. Like any large system, oil and gas objects require the use of a whole hierarchy of models – from differential to integral, from deterministic to adaptive, capable of describing not only different levels of organization of systems, but also the interaction between these levels. The solution of all these tasks

in hierarchical modeling of the processes of the oil and gas industry is engaged in scientific engineering (SciencEngineering) – the field of science, located at the junction of system engineering, basic sciences and cybernetics (Fig. 1).

In this paper, we will consider examples of the approaches of scientific engineering to solving problems that have either not been solved previously in the oil

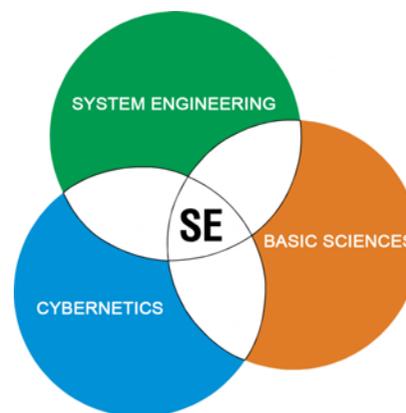


Fig. 1. Scientific Engineering (SE) – at the junction of areas of various hikes

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and gas industry or have been solved in other fields of science for other types of problems. In other words, it will be shown how examples of solving problems of fundamental physics, chemistry, and other natural sciences can be applied to solving problems of oil and gas production.

### Geological modeling: application of the spectral approach for modeling geophysical fields

The development of a spectral approach to the problems of geological modeling was first presented in (Baykov et al., 2010), in which the authors proposed a method based on decomposing the logging into coefficients in an orthonormal basis in the space of functions integrable with the  $L_2$  square. The method was further developed in works (Baykov et al., 2012; Khasanov et al., 2015), in which a more detailed study of the theoretical foundations of the spectral method was carried out, as well as some results of calculations based on the spectral method of geological modeling were presented. It is also worth mentioning that the spectral analysis of logging has been used for lithofacies analysis (Khasanov et al., 2014).

Spectral method of geological modeling – a method of modeling three-dimensional cubes of geophysical properties based on well data. The mathematical model adopted in the spectral method of geological modeling is represented by the simulated region  $D \subset \mathbf{R}^3$  by the stochastic field  $G(x, y, h)$  defined on this region and defined on a certain probability space. For such a model, well data for vertical wells with a fixed lateral coordinate  $(x^*, y^*)$  is a random process, parameterized by a variable characterizing the depth  $G(x^*, y^*, h) = f(h)$ . If the simulation involves  $N$  wells with coordinates  $(x_p, y_p)$  at which the simulated property is given by functions  $f_i(h)$ , then these functions can be considered as the known values of a certain realization of the stochastic field  $G(x, y, h)$ .

The general principle of the spectral method consists in the sequential implementation of several steps: expansion of the functions  $f_i(h)$  according to some orthonormal basis, modeling of expansion coefficients in the interwell space, recovery of the simulated stochastic field using these coefficients at each point of the region  $D$ .

It is known that in the Hilbert space of square-integrable functions ( $L_2$ ) ortho-normal bases exist that allow one to decompose any function defined in this space into a series in terms of the expansion coefficients determined uniquely. The functions defining the simulated property as functions with finite energy belong to this space. Let us choose in the  $L_2$  space a basis of the Legendre polynomials  $P_j(h)$  which we use to decompose the functions  $f_i(h)$ :

$$f_i(h) = \sum_j c_j^i P^j(h), \quad (1)$$

where the coefficients  $c_j^i$  are defined as a scalar product in the space  $L_2$ . The set of expansion coefficients  $c_{ji}$  for each level of decomposition  $j$  is defined at points  $(x_p, y_p)$ , which are well coordinates, and are known values of some realization of the stochastic field  $c_j(x_p, y_p)$ .

To simulate the coefficients  $c_j^i$  for all  $(x, y)$ , the spectral modeling method is used (Prigarin, Mikhailov, 2005), based on the theorem on the integral representation of random processes and fields.

The construction of the conditioned implementation of the simulated  $c_j(x_p, y_p)$  field with known  $c_j^i$  values is generally accepted for two-step simulation methods – the difference between kriging based on known data and data obtained as a result is constructed (Dyubryul, 2002).

As a result of the implementation of the above steps, we obtain a set of realizations of the stochastic fields of the expansion coefficients  $c_j(x_p, y_p)$ , which are caused by the downhole values of  $c_{ji}$ . To restore the implementation of the entire field  $G(x, y, h)$  at each point of the simulated region  $D$ , summation of the basis functions is carried out according to the simulated coefficients:

$$G(x, y, h) = \sum_j c_j(x, y) P^j(h). \quad (2)$$

By virtue of construction, the field implementation is caused by well data and reproducing the statistical characteristics of the source data.

The spectral modeling method has significant advantages over classical modeling methods, such as, for example, sequential Gaussian modeling. In particular, this method is devoid of the main limitation of classical methods – the hypothesis of stationarity of the modeled property. It is known that most geological processes occurring in nature are non-stationary. A significant advantage of the method is a nonparametric periodogram statistical analysis, instead of the classically used parametric variogram analysis, which does not allow a full assessment of the whole range of variability of the modeled property. The spectral method, by virtue of the algorithm of its construction, is fundamentally parallelizable, which makes it easy to scale calculations. In addition, the method implements building a model without reference to a grid (so-called grid-free simulation), which allows modeling on grids of any configuration and complexity, grinding part of the grid and refining the model in this area and, finally, combining generating implementations of the simulated property in various areas of the model. The performance gain of spectral modeling at a typical workstation of a geologist-modeler is 2 to 4 times as compared with classical methods, depending on the size of the generated model.

The application of the spectral method in practice demonstrated its ability to reproduce well the geophysical fields in the interwell space and in undrilled areas, especially when compared with traditional modeling methods (Fig. 2) (Khasanov et al., 2014; Prigarin, Mikhailov, 2005).

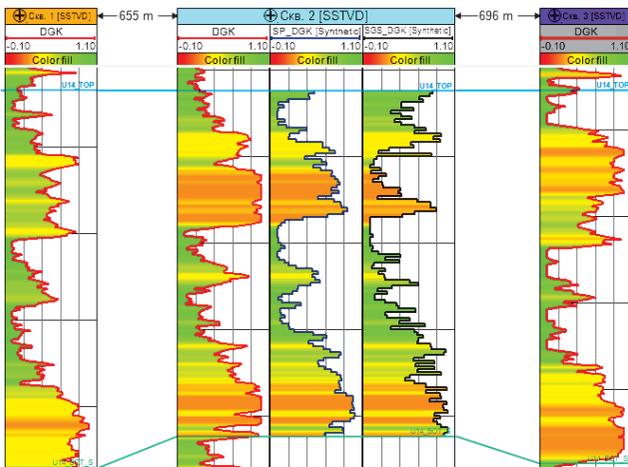


Fig. 2. Comparison of real and synthetic gamma logging curves. DGK, red curve – real logging, SP\_DGK, blue curve – synthetic logging modeled by the spectral method, SGS\_DGK, black curve – synthetic logging modeled by the SGS method.

### Hydrodynamic modeling: the method of sources in the optimization of technological calculations

There are three main groups of methods for solving the differential equation of piezoconductivity (and the heat and diffusion equations that coincide with it) for filtering a fluid in a porous medium: analytical, numerical, and mathematical modeling methods. The analytical methods include: the classical direct integration method, the operational methods (the Laplace integral transform method) and the source method.

The classical method of direct integration consists in finding a set of partial solutions that satisfy the differential equation of piezoconductivity, and then their imposition (superposition), to find the function of interest. In this case, each of the particular solutions is sought, as a rule, in the form of a product of two functions, one of which depends on time, and the other on coordinates. In the underground hydrodynamics, the classical method has found very limited application due to purely mathematical difficulties arising from its use even for relatively simple technological schemes.

Operational methods (in particular, the Laplace integral transformation method) are widely used in petroleum engineering to solve the problem of filtering liquid and gas in a reservoir. In this case, it is not the function itself (the original) that is studied, but its modification (image), obtained by multiplying the original by the exponential function, and the image is integrated within certain limits. After solving the problem in the images, finding the original, i.e. the function describing the pressure field is produced by inverse transformation.

The third method, namely the source/drain method, is a flexible mathematical tool, convenient in engineering applications. It is relatively simple to use

the source method to write an integral that satisfies the piezoconductivity differential equation and boundary conditions; the next task is to calculate its value. In the classical and operational methods, the main task lies in finding the integral itself, which is much more difficult.

The method of sources can be used to solve two-and three-dimensional problems of unsteady filtering both to wells with simple geometry, and complex, with fracture and horizontal wells. In our terminology, a source is a point, line, surface, or volume from which fluid is drawn from a formation (or injected into a formation).

In the present paper, we consider an example of using the source/drain method to solve the problem of choosing the optimal time for injection wells (Sitnikov et al., 2015). The development time is the period of operation of the well in the production mode before putting it into injection.

The pressure distribution from a vertical well, for which the fluid dynamics is given, is written in the form of the Duhamel integral:

$$P(r, t) = P_0 + \frac{\mu}{4\pi Kh} \int_0^t \frac{q(\tau) e^{-\frac{r^2}{4\lambda(t-\tau)}}}{t-\tau} d\tau \quad (3)$$

where  $\lambda = \frac{K}{m\mu C}$  is the coefficient of piezoconductivity,

$P_0$  is the initial reservoir pressure,  $\mu$  is the oil viscosity,  $K$  is the permeability,  $h$  is the formation thickness,  $C$  is the overall compressibility,  $m$  is the porosity,  $r$  is the distance from the source,  $t$  is the calculation time,  $\tau$  is an integration variable.

The problem of determining the flow rate of a well fluid, acting at a constant bottomhole pressure, is reduced to finding the function from the integral equation (3).

For a piecewise constant flow rate of a fluid, expression (3) transforms into equation (4):

$$q^n = \frac{4\pi Kh(P_c - P_0)}{\mu} \frac{\sum_{k=1}^{n-1} q^k \left[ Ei\left(-\frac{b}{n+1-k}\right) - Ei\left(-\frac{b}{n-k}\right) \right]}{Ei(-b)}, \quad (4)$$

$$b = \frac{r_c^2}{4\lambda\Delta t}$$

where  $q^n$  is a piecewise constant flow rate at each step,  $P_c^n$  is the bottomhole pressure,  $r_c$  is the well radius,  $n$  is the number of time steps,  $Ei(-x) = \int_x^\infty \frac{e^{-x}}{x} dx$  is the integral function,  $\Delta t$  is the time step.

Note that, in deriving equation 4, a linear source solution was used, which, in turn, was obtained under the assumption that the wellbore radius is small. In the overwhelming majority of practical situations, this approximation is justified.

Using the principle of superposition (which is ensured by the linearity of the piezoconductivity equation), we can calculate the dynamics of unsteady flow rates for a system of N wells:

$$\sum_i^N q_i^n Ei \left( -\frac{br_{ij}^2}{r_c^2} \right) = \frac{4\pi Kh}{\mu} [P_{c,j}^n - P_0] - \sum_i^N \left\{ \sum_{k=1}^{n-1} q_i^k \left[ Ei \left[ -\frac{br_{ij}^2}{(n+1-k)r_c^2} \right] - Ei \left[ -\frac{br_{ij}^2}{(n-k)r_c^2} \right] \right] \right\},$$

$j = 1..N. \tag{5}$

For fractures of finite conductivity, the system of equations (5) must be supplemented by a system of equations for calculating bottomhole pressures at sources simulating fractures.

The task of optimizing the time of the development of injection wells in production is to determine the duration of production of fluid from injection wells, at which the cumulative discounted production from the development element will be maximum:

$$\max_T \{Q_{dsc}(q(t), T, r)\} \tag{6}$$

Discounted production from a development element is understood as total discounted production from one injection well and the number of production wells corresponding to the selected development system.

The proposed approach allows one to determine the optimal time for testing injection wells with given reservoir properties of the reservoir, parameters of the development system and process parameters. This method formed the basis of the calculation module, which allows to calculate the dynamics of production of a production and injection well, as well as the dependence of accumulated discounted production from a development unit on the time of injection wells.

The reliability of the calculations by the proposed method was checked by a comparative analysis of the dynamics of fluid production with the results of calculations in a commercial software product and analytical dependencies obtained in the article (Khasanov et al., 2013). Testing was carried out on the basis of data on the structure of one of the fields of PJSC Gazpromneft. The obtained dependence of the dimensionless accumulated discounted production on the time of the injection well testing is shown in Fig. 3. It can be seen that the largest discounted production can be obtained subject to the use of injection wells in production for about nine months. An earlier or late transfer of wells would be less cost effective. This result was not only confirmed by a series of calculations on a full-scale hydrodynamic model, but also agrees with the characteristic time of well transfer, which was obtained experimentally during the operation of the field (Sitnikov et al., 2015).

The considered example shows that analytical and, as it is often said now, semi-analytical methods have not lost their relevance in solving engineering problems, even despite the rapid growth in the productivity of computing equipment and, therefore, numerical methods.

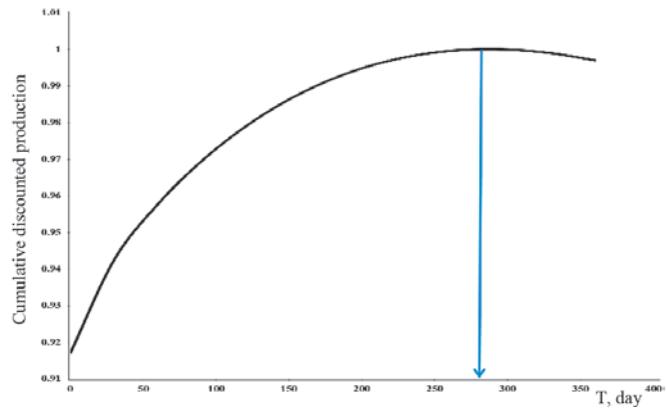


Fig. 3. The dependence of the dimensionless discounted production  $Q_{dsc}/\max(Q_{dsc})$  on the transfer time of the well to the injection  $T$  (Sitnikov et al., 2015)

### Geomechanics: comparison of parameters of hydraulic fracturing in dimensionless variables of design and hydrodynamic studies

Due to the frequent use of hydraulic fracturing (GF) technology in oil and gas fields, there is a large amount of statistical information on conducted operations. Based on the results of processing this information, it is possible to conclude about the effectiveness of the hydraulic fracturing carried out, which will make it possible to make adjustments to the design and develop further recommendations. However, this task is complicated by the fact that, when conducting hydrodynamic studies in wells with hydraulic fracturing, it is found that the values of fracture parameters, in particular, half the length, differ significantly from those planned by design.

Below are the results of a study of the possible causes of this discrepancy using dimensionless variables, the introduction of which allows for the analysis of information on the performed fracturing operations.

From the graph shown in Fig. 4, it can be seen that in the general case there is no obvious relationship between the fracture length and the injection volume. The reasons that led to this are fairly obvious, and the fact is that, in addition to the injection volume of the cross-linked

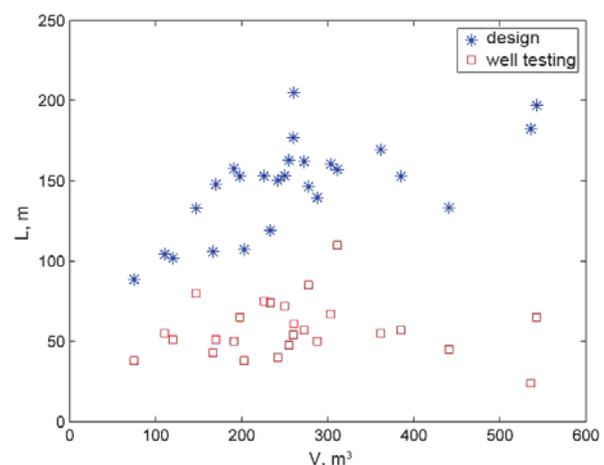


Fig. 4. Dependence of the fracture length in design and well testing on the volume of injected fluid

gel (and the associated mass of the proppant), the formation parameters such as the Young’s modulus for the section, the thickness of the layers compressing stresses perpendicular to the fracture, fracture toughness coefficients, as well as the technological parameters of the design of the hydraulic fracturing – fluid rheology, injection rate and proppant concentration.

To analyze the obtained data, it is required to find a sample of wells that would be completely identical in all parameters of the fracture except for one, after which this procedure should be repeated for all parameters of the fracturing to determine the degree of influence of each of them. Having determined these degrees of influence, it would be possible to establish the most significant parameters for the fracture geometry. This would suggest the parameters, the error in which could lead to a significant systematic discrepancy between the length of the fracture, planned for the design, and the length of the fracture, obtained by hydrodynamic studies of the well. In practice, however, it is not possible to select such samples of fractures that would not differ in all parameters except one.

All cases are selected so that the injected fluids of the hydraulic fracturing are identical, including the concentration of the polymer. Then we can talk about the similar rheology of fluid fracturing for these cases. Thus, at least for this parameter, the data of the fracturing operation are identical.

For the method proposed in this article, this is a prerequisite.

The design fluid injection rates also vary slightly in design, so that this factor could not have a decisive impact on the large scatter and formation of a “cloud” in Fig. 4.

Thus, mostly various geomechanical parameters remain that can vary along the reservoir quite significantly (especially the thickness of the reservoir). A successful statistical analysis requires a method that reduces the dimensionality of the problem according to these parameters, and leads to fractures in reservoirs with different geomechanical properties to the same “denominator”. Such a method is the introduction of dimensionless parameters of the problem of the development of a fracturing.

The fracture propagation according to the Planar3D model in the case of the injection of non-Newtonian fluid is described by three laws (Khasanov et al., 2017):

- Hooke’s law;
- The law of viscous friction;
- The law of conservation of mass.

We will conduct the de-dimensioning of the equations in the same way as described in (José I. Adachi et al., 2010) for the case of non-proppant fractures; we will also assume that there are no leaks in the reservoir, Young’s modulus is homogeneous, and lithology is three-layer

and symmetric. As a result, we obtain the following list of dimensionless parameters:

$$\gamma = \frac{k' E'^{2n+1} Q^n}{H^{3n} \Delta \sigma^{2n+2}} \tag{7}$$

$$\tilde{V} = V \frac{k' E'^{2n+2} Q^n}{H^{3n+3} \Delta \sigma^{2n+3}} \tag{8}$$

$$\tilde{L} = L \frac{k' E'^{2n+1} Q^n}{H^{3n+1} \Delta \sigma^{2n+2}} \tag{9}$$

$$\tilde{C} = \frac{C_l H^{\frac{3n}{2} + \frac{1}{2}} \Delta \sigma^{n + \frac{1}{2}}}{k'^{\frac{1}{2}} E'^n Q^{\frac{n}{2} + \frac{1}{2}}} \tag{10}$$

$$\tilde{K} = \sqrt{\frac{2\pi}{H} \frac{K}{\Delta \sigma}} \tag{11}$$

where  $E' = \frac{E}{1-\nu^2}$  is the flat strain modulus,  $E$  is Young’s modulus,  $\nu$  is Poisson’s ratio,  $n$  is the fluid behavior,  $k'$  is the flow density coefficient,  $Q$  is the fluid flow,  $H$  is the formation thickness,  $\Delta \sigma$  is the stress contrast,  $L$  – half-length of a fracture,  $V$  – volume of injected fluid,  $C_l$  – leakage coefficient according to Carter,  $K$  – coefficient of fracture resistance.

Comparing the obtained dimensionless variables with those given in the article (José I. Adachi et al., 2010) for the Pseudo3D model, one can see that they are identical up to constants. The only important difference is the  $\gamma$  parameter. It is clear from the work that if we divide the reservoir thickness by the length scale factor from this work, then the dimensionless parameter  $\gamma$  is obtained, up to a constant. Its physical meaning is the ratio of the thickness of the reservoir to the fracture length attained.

As a result, the non-dimensioning decreases the dimension of the problem by 5, since the Young modulus, the Poisson’s ratio, stress contrast, reservoir thickness and fluid viscosity are replaced by one dimensionless parameter  $\gamma$  (7). Obtaining dimensionless parameters makes it possible to carry out an analysis of the work done by the hydraulic fracturing, namely, to identify some regularities when comparing the half-lengths obtained in design and well testing in comparison with the total injection volume. Thus, the necessary data for analysis in addition to the values of half-lengths of fractures are: reservoir thickness, Young’s modulus and Poisson’s ratio (included in the flat strain module), stress contrast in the reservoir, rheology of the injected fluid, fluid flow and total injection volume of the formation fluid. Strength properties of rocks in this analysis are not taken into account. Figures 5-7 show the dependence of the dimensionless length on the dimensionless volume for three types of injected fluid. From the graphs it can be seen that the predicted dependence of the dimensionless parameters is preserved, only the degree depending on the rheology of the injected fluid differs. In this case, the degree dependence is preserved both for the data

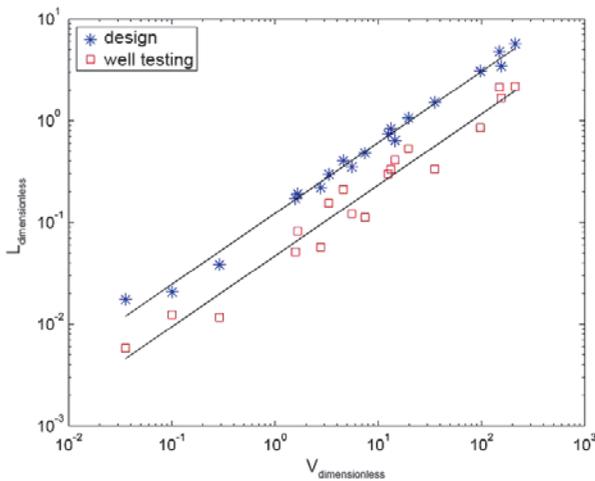


Fig. 5. Dependence of the dimensionless fracture length on the dimensionless volume: liquid 1,  $m/p A$ ;  $\alpha = 0.69$

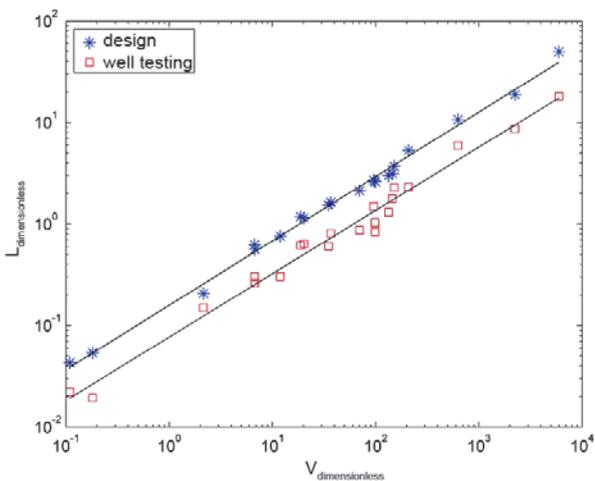


Fig. 6. Dependence of the dimensionless fracture length on the dimensionless volume: liquid 2,  $m/p A$ ;  $\alpha = 0.63$

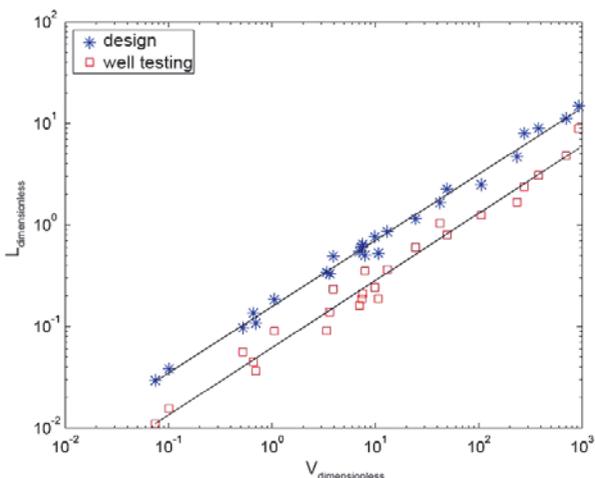


Fig. 7. Dependence of the dimensionless fracture length on the dimensionless volume: liquid 3,  $m/p A$ ;  $\alpha = 0.66$

obtained by design and hydrodynamic studies.

The above results prove that the dependence of the dimensionless fracture length on the dimensionless volume is a degree dependence:

$$\tilde{L} = A \cdot \tilde{V}^\alpha \tag{12}$$

Then substituting expressions (7) and (8) into (12),

we can obtain a formula reflecting the dependence of the dimensional length of a fracture on the injection volume for an arbitrary degree  $\alpha$ :

$$L = A \frac{H^{3n+1-(3n+3)\alpha} \Delta\sigma^{2n+2-(2n+3)\alpha}}{k'^{1-\alpha} Q^{n(1-\alpha)} E'^{2n+1-(2n+2)\alpha}} V^\alpha \tag{13}$$

From the graphs (Fig. 5-7), it can be concluded that the degree of dependence of the dimensionless fracture length on the injection volume  $\alpha$  is in the range of 0.6-0.7. By taking the degree of dependence equal to 0.6, and the indicator of the behavior of a fluid  $n$  equal to 0.5, you can get an empirical formula for calculating the half-length of a fracture:

$$L = A \frac{\Delta\sigma^{\frac{3}{5}}}{H^{\frac{1}{5}} k'^{\frac{2}{5}} Q^{\frac{1}{5}} E'^{\frac{1}{5}}} V^{\frac{3}{5}} \tag{14}$$

This formula allows you to evaluate the effect of error (geomechanical parameters) or changes in input parameters (process parameters) on the change in the half-length of the fracture (Table 1).

Parameter	Geomechanical parameters			Process parameters	
	$H$	$E'$	$\Delta\sigma$	$k'$	$Q$
+10%	- 2%	- 2%	6%	- 4%	- 2%
+20%	- 4%	- 4%	12%	- 8%	- 4%
+30%	- 6%	- 6%	18%	- 12%	- 6%

Table 1. The effect of changing parameters on the change of fracture length

In this paper we analyzed the problem of the divergence of half-lengths of fractures in design and in hydrodynamic studies of the well. For the analysis we applied the method of dimensionless variables, developed on the basis of parametrization of the fundamental equations of hydraulic fracturing. The dependence of the half-length of the fracture on the injection volume, geomechanical parameters and rheology of the fluid is analyzed. This method allowed us to reduce the dimension of the problem and obtain a fairly universal empirical degree dependence of the dimensionless length on the dimensionless volume, which in its dimensional form gives a simple empirical formula for estimating the fracture length. It is concluded that the geomechanical parameters have a weak effect on the fracture length. The validity of the equations used in modeling hydraulic fracturing has been confirmed.

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# Anisotropic anelastic seismic full waveform modeling and inversion: Application to North Sea offset VSP data

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**Abstract.** In sedimentary basin, elastic anisotropy can be described by a transverse isotropic medium and the attenuation in the seismic bandwidth can be approximated by a quasi-constant quality factor. Very few full waveform inversions were conducted for such realistic media to show the feasibility and the benefit of this approach. For illustration, we have chosen two offset VSP datasets from the North Sea displaying attenuated phases and where the medium is known to be transverse isotropic. By inverting elastic parameters, anisotropy, shear attenuation and source functions, we have been able to find an Earth model reproducing fairly the real data. By exploiting all the information in the seismograms, full waveform inversion allows us to localize and characterize the Brent gas reservoir target.

**Keywords:** modeling, anisotropy, full waveform inversions, VSP

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## Introduction

Anisotropy is often observed due to the thin layering or aligned micro-structures, like small fractures. This type of anisotropy can be described by vertical (VTI) and horizontal transverse isotropy (HTI) when, respectively, layering is horizontal and the cracks are vertical. Moreover, the elastic approximation of Earth properties for seismic wave propagation is limited as waves undergo attenuation and dispersion that can be described by a quasi constant quality factor over the seismic bandwidth. Anelastic and anisotropic parameters need to be taken into account for a consistent seismic full waveform inverse problem. If the redundancy in the seismic surface data allows us to neglect many wave phases in the seismograms such as P to S wave conversions, the scarcity of data in borehole seismic, especially for offset VSP (OVSP), challenges us to interpret the full content of the seismograms. For that reason, the complexity of the wavefield (reflections, transmissions, phase conversions, etc. seen in the seismograms) needs to be accurately modeled. According to the review done by Virieux and Operto (2009) about full waveform inversion, the reconstruction of anisotropic parameters is probably one of the most undeveloped and challenging fields of investigation and they conclude that incorporating more sophisticated wave phenomena (attenuation, elasticity,

anisotropy) in modeling and inversion is another field of investigation to be addressed. On one hand, the full waveform inversion for visco-elastic parameters in time domain have been proposed by Charara et al. (2000) and Barnes et al. (2004). The feasibility and practicality of this approach has been demonstrated on several noise free synthetic data: for a 1D offset VSP numerical inversion experiment (Barnes et al., 2004) and for a 2D crosswell numerical inversion experiment (Charara et al., 2004) and successfully tested on real data (Barnes and Charara, 2009). In addition, a feasibility study of the full waveform inversion for VTI parameters for a synthetic seismic crosswell data shows a reliable reconstruction of the Earth model even with noisy data (Barnes et al., 2008).

Based on these previous studies, we investigate the benefit of simultaneous full waveform inversion of elastic parameters, VTI Thomsen parameters and shear Q-factor when applied to two North Sea OVSP datasets.

## Visco-anisotropic modeling in time domain

The linear visco-elasticity constitutive law, for a quasi constant quality factor, is modeled by the superposition of relaxation mechanisms, classically called Zener or standard visco-elastic bodies. The key concept of this technique is the replacement of the time convolution between relaxation rates and strain by a set of first order temporal partial differential equations, storing the strain history interactions with the medium through new fields called strain memory variables (Carcione, 1990). The full set of visco-elastodynamic equations using this

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constitutive relation can be solved numerical by the finite difference method. Furthermore, the seismic modeling is based on the cylindrical system of coordinates by assuming azimuthal invariance of the propagation fields. The 3D Green function can be modeled as a 2D numerical problem by assuming axi-symmetry of the medium and the wavefields (Igel et al., 1996). The wave propagation equation is discretized using a 4th order staggered grid finite difference scheme for the cylindrical system of coordinates. This scheme allows one to model VTI anisotropy.

### The inversion method and procedure

The inverse problem, solved by local optimization methods, can be expressed as the minimization of a misfit function (Tarantola, 1987). For the case of least squares, the misfit function is a scalar function defined over the model space as  $S(\mathbf{m}) = \Delta \mathbf{d}^T \mathbf{C}_D^{-1} \Delta \mathbf{d} + \Delta \mathbf{m}^T \mathbf{C}_M^{-1} \Delta \mathbf{m}$ , where symbols are defined as follow: On the model domain,  $\mathbf{m}$  is a model,  $\Delta \mathbf{m} = \mathbf{m} - \mathbf{m}_{pr}$  is the difference between the model  $\mathbf{m}$  and the *a priori* model  $\mathbf{m}_{pr}$  and  $\mathbf{C}_M$  denotes the model space covariance matrix; On the data domain,  $\Delta \mathbf{d} = \mathbf{g}(\mathbf{m}) - \mathbf{d}_{obs}$  are the residuals, i.e., the difference between the observed data  $\mathbf{d}_{obs}$  and the synthetic data  $\mathbf{g}(\mathbf{m})$  obtained by simulation of the wave propagation; and,  $\mathbf{C}_D$  denotes the covariance matrix over the data space. The misfit function measures the discrepancy between observed and synthetic data, and also between the model and the prior model. The reference misfit used to normalize the current misfit is obtained for  $\Delta \mathbf{d} = \mathbf{d}_{obs}$  and  $\Delta \mathbf{m} = \mathbf{0}$ . The minimization of the misfit function is performed using a conjugate gradient method. The iterative process of a non linear inversion is developed by Tarantola (1987); the expressions of the Fréchet derivatives for the elastic parameters and for the source function can be found in Tarantola (1986) and for the visco-elastic parameters in Charara et al. (2000).

In the present inversion, we invert for the P and S-wave velocities, the density, the Thomsen parameters  $\varepsilon$  and  $\delta$  for VTI anisotropy, the shear quality factor Qs and the source time functions. All the parameter fields are 2D except for the Qs parameter which is considered 1D at this stage of the study for stabilization purpose. The model covariance matrix is filled with independent horizontal and vertical Laplacian correlations (Charara et al., 1996). The inversion procedure starts from the prior model: a stratified model inferred from travel time inversion and well logs. Then, four inversions are performed successively. From one inversion step to the next, the spatial correlations decrease while the frequency content of inverted data is increased.

### North Sea Offset VSP data

The Lille-Frigg field is located on the eastern margin of the Viking Graben, about 22 km north-east of the Frigg

field. The structure consists of a narrow N-S elongated horst with gas trapped in the Brent reservoir. The Brent formation is known to be very variable in thickness and facies. The well 25/2-C1H drilled in Lille-Frigg field encountered a fault dipping east and only the lower part of the Brent formation (Minsaas et al., 1994).

Two three component OVSP datasets were acquired with the aim of better defining the structural position of the fault plane and to ascertain the distance of the whole Brent formation from the well (Muller and Ediriweera, 1993). Based on the interpretation of these OVSPs, of logging data, high resolution borehole imagery and other seismic data (walkaways and other OVSPs), a side track 200 m west of the well was drilled finding the total sequence of the Brent formation (Minsaas et al., 1994).

The acquisition geometries of the two OVSPs are shown in Figure 1, they are denoted "West" and "East" and shots are aligned with the well. The well is vertical, the source offset is 2 km for both shots and the data were collected at depth levels ranging from 2300 m down to 3950 m.

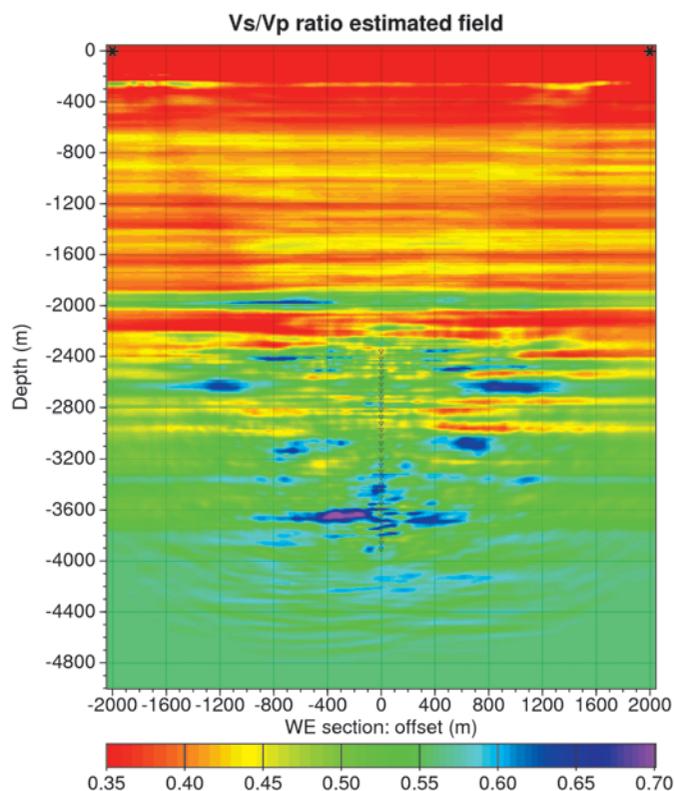


Figure 1. S-wave velocity over P-wave velocity ratio field. The acquisition geometries of the West and East OVSP are shown: stars near the surface denote the sources location while down triangles denote the receiver locations. The resolved region depends on the wave: the direct P-wave illuminates a triangular region from the source to the antenna, the down-going converted P-S at the antenna depth illuminates a region close to the well, the reflected waves illuminate region below the bottom of the well. The Vs/Vp ratio allows to clearly distinguish the gas bearing reservoir from other formations (purple region).

### Inversion results and discussion

The presented inversion results are for the 4th inversion (20Hz). The synthetic data obtained at the convergence are shown in Figure 2 as well as the corresponding observed data and residuals for the west OVSP. The fit is fair; the remaining misfit is 20%. Moreover, the major part of the residuals is unstructured noise.

plotted on the same figure as well as the side track of the well.

The inverted attenuation parameters are very smooth but show strong attenuation in the first layers below the water bottom necessary to explain the attenuated converted S-wave from the sea floor. The gas reservoir attenuation is not resolved due to the 1D inversion for the attenuation parameter. The anisotropic parameters

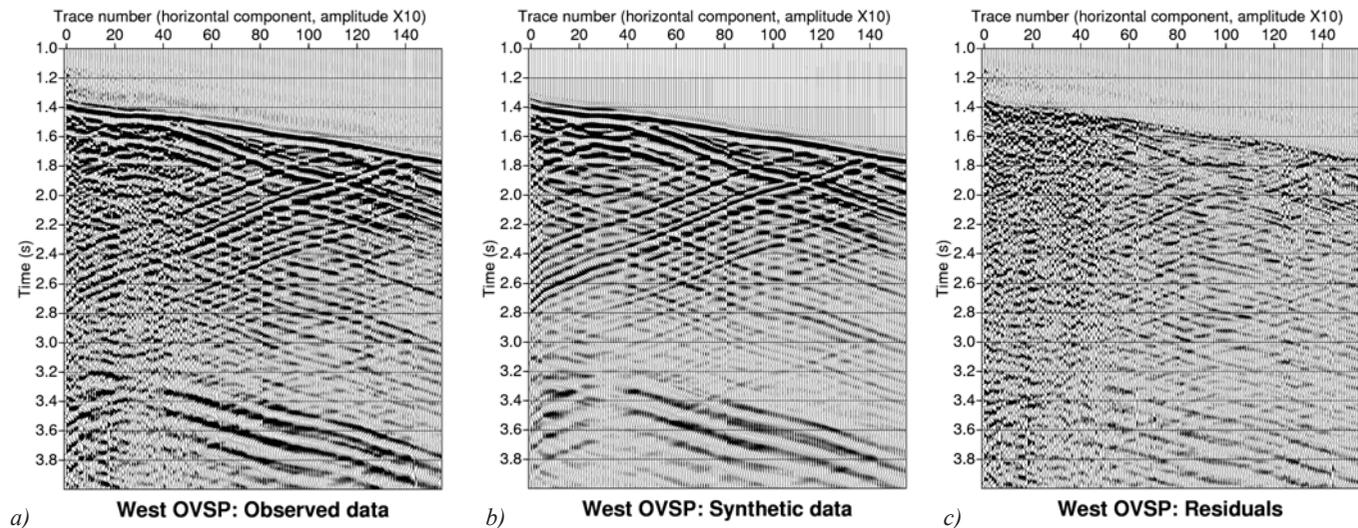


Figure 2. Horizontal component of the West OVSP data. Low-pass filtered observed data (corner frequencies of 20 and 40Hz), synthetic data and residuals are displayed respectively at left, on the middle and at right. The fit between observed and synthetic is fairly good providing low residuals (remaining misfit is 20%). Structured energy in the residuals shows that some reflected and transmitted S-waves are not fully explained.

The inverted source time function for the West offset VSP is shown in Figure 3. The high frequency content of the source is increasing during the inversion process as the frequency content in the observed data has been increased from the previous inversion step.

cannot be well resolved due to the limited number of shots and therefore the limited range of incidence angles. The Thomsen  $\epsilon$  and  $\delta$  estimated fields provide poor information in absolute value ( $\epsilon$  is shown in Figure 4) but some anomalies seems to be associated to real anisotropic layers. The inverted elastic parameters are of main importance in order to identify and delimitate the gas bearing reservoir as shown in Figure 4 ( $V_s/V_p$  ratio and the Poisson ratio fields). However, the west/east extension of the resolved region in the images is limited to the well vicinity (from 200 m to 500 m). This is due to the narrow illumination region both for transmitted (down-going) waves and reflected (up-going) waves although multiples or converted waves are inverted. Moreover, the starting model being stratified, the resolved region does not appear clearly.

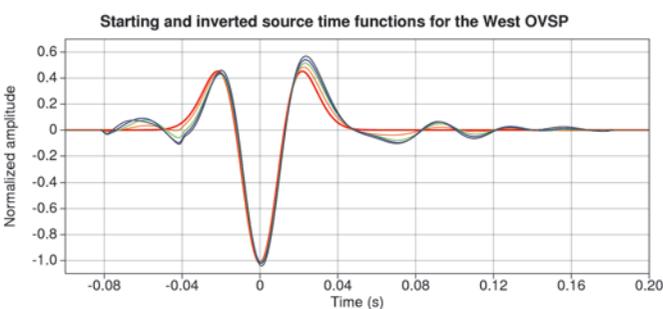


Figure 3. Source time function for the 4<sup>th</sup> inversion of the West OVSP data. The starting wavelet is denoted by the thick red line while the thin orange, green, blue and black lines denote respectively the inverted wavelet at iteration 5, 20, 50 and 100.

The field representing the  $V_s/V_p$  ratio is plotted in Figure 1 and is a good indicator of the gas bearing reservoir zone. The other estimated parameter fields are zoomed in Figure 4 displaying complementary structural and petrophysical information. The geological interpretation provided by (Minsaas et al., 1994) is

The next stage is to define a better, likely 2D, prior model, to better understand the coupling of the shear attenuation inversion with source inversion, to introduce a compressive attenuation parameter and finally to provide a posterior resolution map for each estimated parameter field.

### Conclusions

The simultaneous inversion of elastic, VTI Thomsen parameters and shear Q-factor allows us to extract more

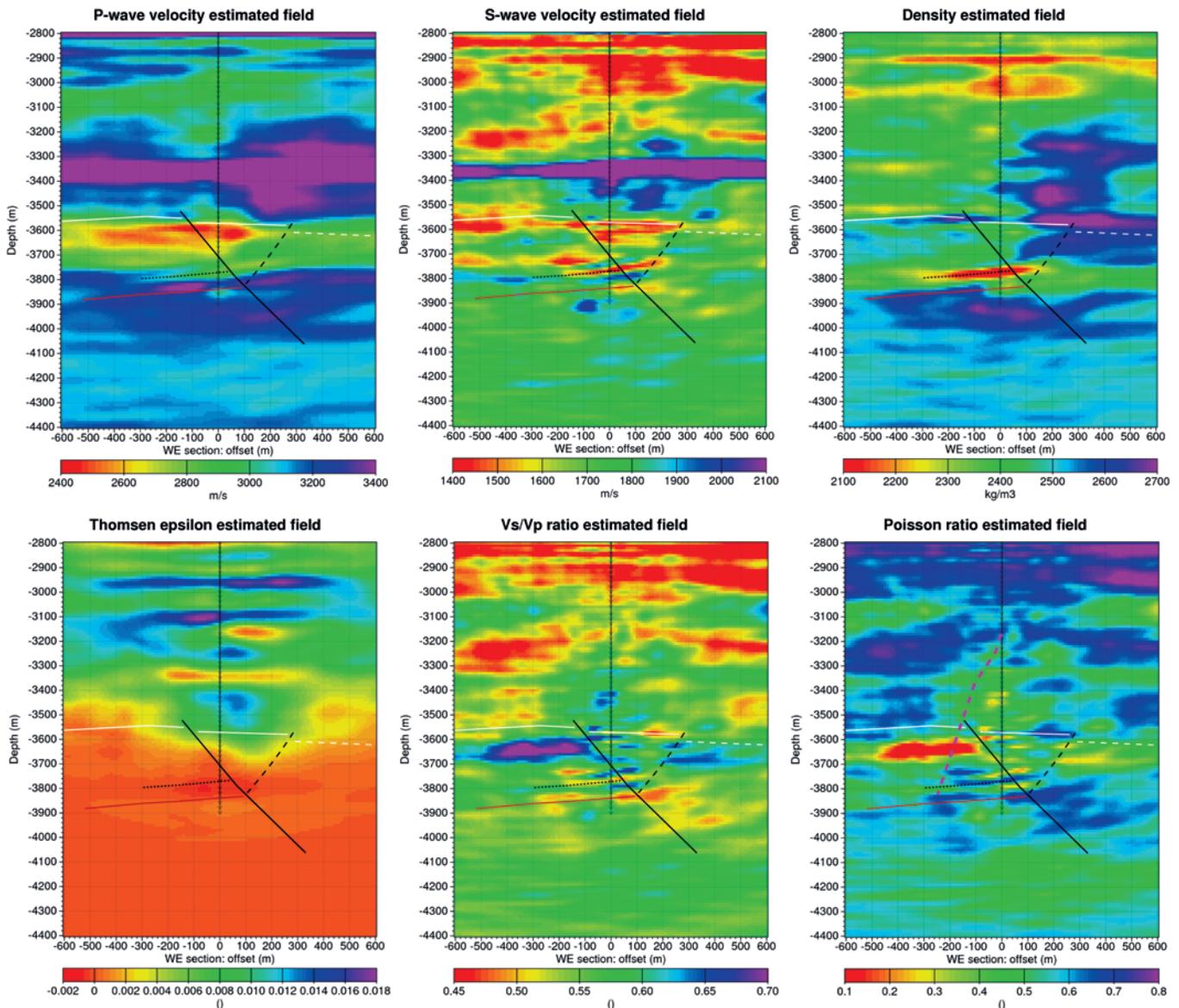


Figure 4. Images of the estimated elastic parameter fields in the well neighborhood and below the well. The down triangle denotes the receivers (1 over 2 are plotted). The side track is indicated by the thick magenta dashed line on the Poisson ratio image. The geological interpretation (Minsaas et al., 1994; Mittet et al., 1997) is indicated by thin lines: the black line denotes the major normal fault cutting the Brent formation, the dashed black line is a likely antithetic fault, the white line is the BCU (base cretaceous unconformity), the dotted black line is the coal seismic marker in the lower part of the Brent formation and the dark red solid line is the Brent bottom. The estimated fields provide complementary information on the structure, e.g. the density field allows to localize precisely the coal marker while the short wavelengths of the S-wave velocity field helps identifying the major fault. The  $V_s/V_p$  ratio or the Poisson ratio are good indicators of the presence of gas in the reservoir. According to these fields, the gas bearing region corresponds to the upper part of the Brent formation (in purple for  $V_s/V_p$  ratio and in red for Poisson ratio, at left of the fault). The structure below the well is difficult to interpret. Finally, the anisotropic parameters like the Thomsen  $\epsilon$ , are not well resolved (narrow incidence angle range), only the zones illuminated by the down-going waves are reliable, for instance, the anisotropic layers located near 2980 m and 3100 m.

information from the data. By using the adequate Earth properties, it decreases the modeling “noise” in the inversion process, even if the constraints over certain parameters are weak (and consequently providing a poor resolution). The complexity of the recorded wavefield is fairly reproduced by the synthetic data. In the resolved parts of the model, the results are consistent with the currently admitted structural interpretation, part of the structure being well retrieved. The present anisotropic

visco-elastic full-wave inversion of offset VSPs data from the North Sea illustrates the impact of multi-parameter inversion when using the adequate Earth properties; it shows the feasibility and the benefit of our proposed method.

### Acknowledgments

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# Fracture characterization, modeling and uncertainty analysis of a carbonate reservoir with integration of dynamic data (Middle East)

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**Abstract.** This field case study shows the benefits of fracture characterization and risk analysis. The uncertainty analysis was performed on production, plateau length and ultimate recovery factor. The field has been under production for more than 48 years, nevertheless it has produced less than 2% of the STOIP. Historical data measurements on production rates (wopr, gor, wcut, etc) and pressures (static and flowing) have been used to constrain uncertain parameters during historical period and then propagate it into the prediction. Due to the low cumulative production, fracture characterization uncertainties have been incorporated (Discrete Fracture Network) together with reservoir uncertainties and geological uncertainties. Several surface/controllable parameters have been considered in the analysis evaluation on Plateau Length and Recovery Factor. The risk analysis accounts for two main recovery mechanisms: gas injection from the crest for Gas gravity drainage and periphery downdip water injection with natural imbibition. Several scenarios of DFN's and 43 uncertain reservoir parameters with their probability distribution were considered. Experimental Design and Response Surface Methodology was applied to minimize the number of Reservoir simulation runs of the study. Plackett and Burman Experimental Design was used for the Screening Phase. During the screening phase, it has been revealed that 7 uncertain parameters account for more than 80% of the total variation of Cumulative Oil Production. A detailed Latin Hypercube has been performed with 3 discrete fracture network, controllable uncertain parameters and the 7 most relevant parameters. This risk analysis identified the best cases of each phase of the development, P10 and P90, and the major uncertainties impacting the field development plan. Mitigation, acquisition, and monitoring plan have been defined accordingly to reduce the major impacting uncertainties.

**Keywords:** fracture, modelling, uncertainty analysis, carbonate reservoir

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## Introduction

The decision-making process for field development plans is facing new challenges; managers are encouraged to take decisions under uncertainty rather than deterministic solutions. This practice has been fundamentally transformed in recent years, with many innovative workflows introduced into the literature. There is an increasing recognition of the need to preserve geologic realism during the historical period for more reliable forecasting, and an increasing acknowledgment of uncertainty, and the need to examine multiple history-matched models rather than a single best model for forecasting.

This study presents a practical approach to deal with the difficult problem of the risk analysis in the performance forecast applied to a Fractured Reservoir.

## Methodology

Basically, the proposed methodology (Fig. 1) involves a three-step procedure using Experimental Design and Response Surface Methodology.

## Fracture Reservoir Field Description

The considered Field (Fig. 2) is a fractured and faulted carbonate reservoir.

Oil accumulation is in three main zones. The producing intervals consist of layered chalky limestone with relatively high porosity (20%+) and poor matrix permeability (2-10 MD). These reservoir layers are interbedded with dense, more fractured layers. The overall structure of the field is a broad, NE-SW slightly elongated dome with gently dipping flanks. Production tests, core observations, and FMI/FMS image logs confirm high fracture permeability within open fractures oriented N30E across the crest of the structure. Interpretation of 3-D seismic shows numerous

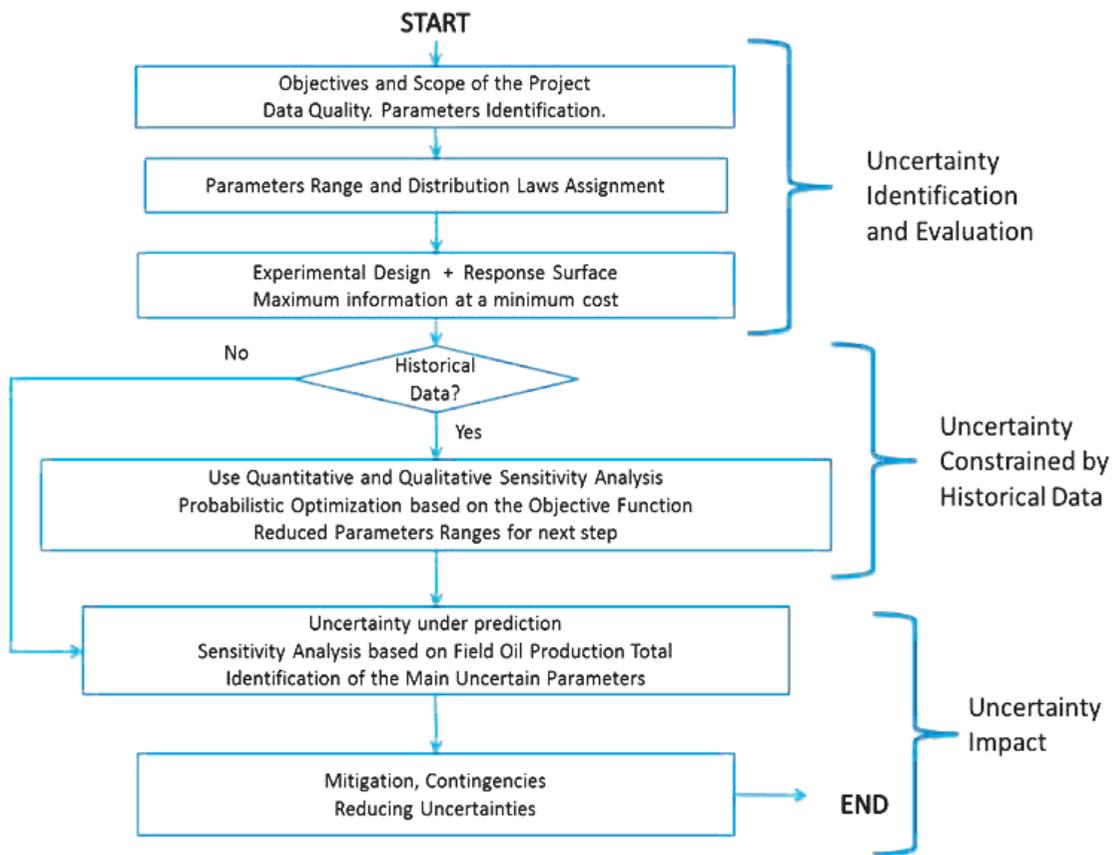


Figure 1. Methodology for Uncertainty Analysis

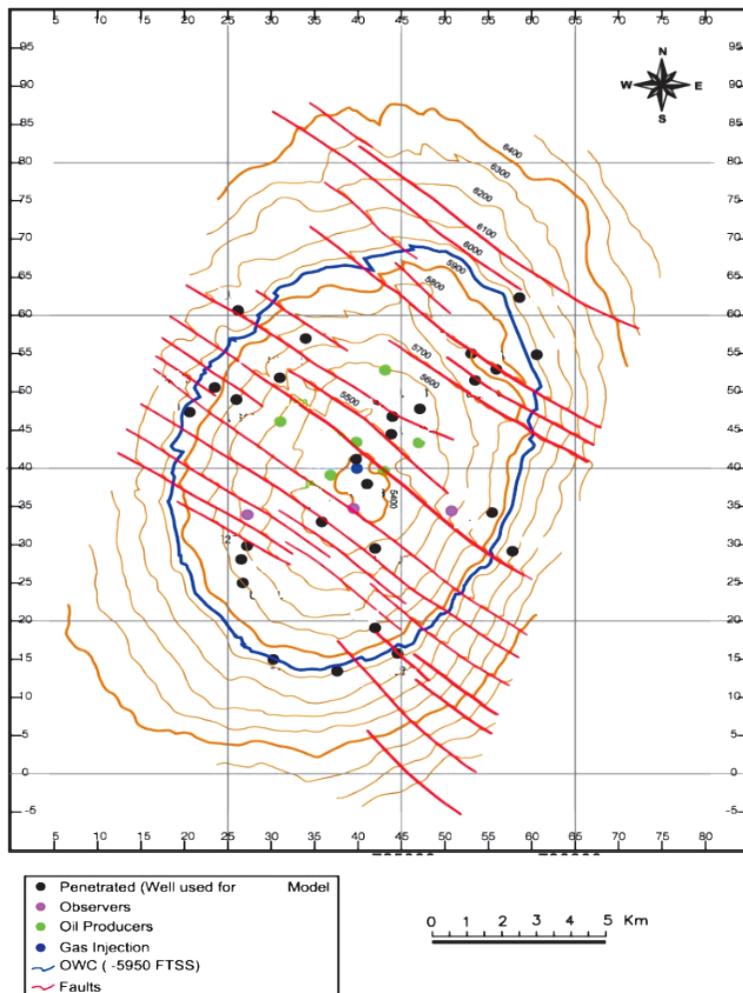


Figure 2. Fracture Reservoir Map

NW-SE striking normal faults with small throws cutting through the reservoirs. These faults are oriented perpendicular to the dominant trend of the open fracture system and are older than the latter NE fault system. The second set of fractures is sub-parallel to the fault trends, it is thought that these fractures are mineralized, they have little effect on fluid flow since they are crosscut by the younger open fractures. Oil viscosity is about 0.7 cp, with an initial GOR of 400 scf/STB. Oil is strongly undersaturated: the bubble point pressure is 1200 psi and the initial pressure of the reservoir was 2925 psi. Oil production started in August 1962 from one well at an average rate of 4468 stbpd of dry undersaturated oil. Available reservoir performance history and pressure data suggested limited water drive and lack of reservoir energy leading to an estimated very low primary recovery. It has been concluded that the best recovery mechanism is gas injection.

### Considered Uncertainties

Forty-three Uncertain Parameters were identified for the following reservoir elements:

- Reservoir Connectivity;
- Fracture and Matrix Properties;
- Rock-Fluids Properties (GOR, Bo, Viscosity ...);
- Controllable Parameters.

Some of the above parameters were applied at the field scale level and some of them applied to layer by layer basis. While the faults system was classified as three sub-set of faults, each set of fault has its own fault transmissibility.

**First Experimental Design: Screening Phase – Plackett and Burman**

Plackett and Burman experimental design is proposed with 44 simulations to evaluate the main effect of each uncertain parameter.

The analysis was focused on Cumulative Oil Production at the end of the Prediction for selecting the most influential variables for Risk Analysis.

Pareto Plot (Fig. 3), based on Global Sensitivity Analysis theory, shows the impact of each uncertain parameter in a percentage contribution of the total variation of Cumulative Oil Production at 01/01/2051. Out of the 43 parameters, there are 7 uncertain parameters contributing to 83% of the total variation of Cumulative Oil Production.

**Second Experimental Design: Uncertainty Analysis Phase – Latin Hypercube**

A Fracture Network Uncertain Parameter has been added at this stage. Each Discrete Fracture Network is an output (with a set of Properties, Fracture Porosity, Fracture Permeability, Block Height Size and Sigma Value) of an assumed continuous parameter named DFN-Case. This parameter represents the fracture extension and connectivity of the system.

On top of these sub-surface uncertain parameters, surface/controllable uncertain parameters have been considered for the Risk Analysis Evaluation.

Uncertainty on Gas Supply has been considered through a Multiplier of Gas Injection.

Wellhead pressure is an encouraging parameter to be considered, it may help recognize upside potential from minor adjustments on pressure.

Finally, restriction on high Gas Production has been considered through a GOR limitation parameter. This final uncertain parameter mainly works by being more restrictive in terms of GOR production.

**Uncertain Parameters Constrained by Historical Data**

In order to perform an uncertainty Analysis on brownfields, it is required to assign a threshold for acceptable solutions. It means that all combinations of uncertain parameters providing a global objective function higher than the threshold will be discarded. This methodology is usually called Uncertainty Analysis Constrained by Historical Data.

**Probabilistic Distributions Analysis**

The impact of all uncertain parameters; constrained and unconstrained by historical data plus surface uncertainties, will be assessed on Cumulative Oil Production at the end of prediction (01/01/2051) as well as Plateau Length. Response surfaces for these targets outputs have been built. Non-Parametric Response Surface has been used for these particular responses in order to have the best possible quality of the response surface, in terms of accuracy as well as Predictivity.

The highest impact on Cumulative Oil Production Variation is due to the DFN-Type. The Diffuse Case Scenario provides an intermediate value of Cumulative Oil Production, N30/130 SSF Case Scenario provides the highest value and finally, the minimum case Scenario provides the lowest value. DFN-type represents more than 45% of the total variation of Plateau Length.

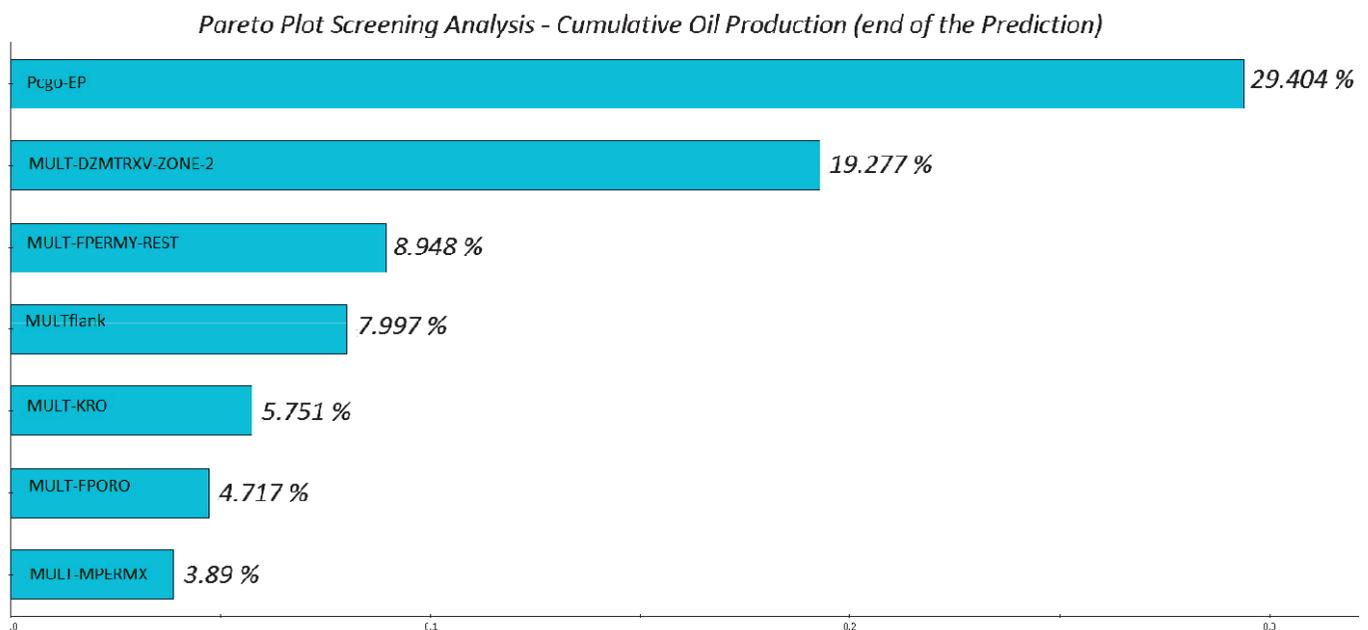


Figure 3. Pareto Plot – Screening Phase

## Mitigation and Contingency Plan

When considering uncertainty reduction for some of the uncertain parameters, it has to be clearly defined the objective (Plateau Length, Cumulative Oil Production, etc.) and the quantification of the reduction in terms of the variation of the response. Parameters being considered for uncertainty reduction are in order of importance as follow:

- DFN Case Type;
- Communication through the dense;
- Communication through the flanks.

Knowledge improvement on those three uncertain parameters will lead to big reductions on the envelope P10-P90 for Plateau Length as well as for Cumulative Oil Production.

For three considered DFN Cases, the main risk on Plateau Length and on Cumulative Oil Production can be mitigated to a large extent with the management of Well Head Pressure.

Providing Flexibility on Well Head Pressure Management depending on the DFN Case Scenario is a key action to be considered for the FDP1 to respect production commitments (Fig. 4).

## Summary and Conclusions

Some of the key conclusions and lessons learned from our experience are as follow:

- It is demonstrated how to mitigate risk of low production and plateau length by controlling key variables (e.g. THP);
- Controllable parameters must be included in any uncertainty analysis to gain flexibility and control in the results;

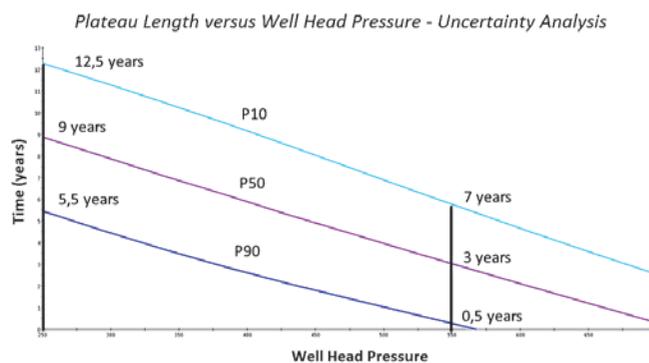


Figure 4. Probabilistic Plateau Length versus Well Head Pressure – Contingency Plan

- This risk analysis demonstrates how to identify the key uncertain parameters playing a role in the selected production targets (production and plateau length);
- Historical Data helps to constrain probabilistic distributions of the most influential parameters;
- Analysis of the most influential uncertain parameters impacting the history matching quality leads to better understanding of the model;
- Output probabilistic distributions help to place the base case in the uncertain domain as well as to define low and high cases for further economic analysis.

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## Probabilistic-statistical estimation of reserves and resources according to the international classification SPE-PRMS

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**Abstract.** Today in the oil and gas industry there is a large number of different classifications of hydrocarbon reserves and resources, each of which has advantages and disadvantages. This work includes analysis, comparison, as well as the possibility of comparing the results obtained at first glance, seemingly, from completely different methods of assessment of hydrocarbon reserves and resources.

The purpose of the paper is to consider the features of calculating hydrocarbon reserves by different methods and to study the feasibility and appropriateness of applying the probabilistic method for reserves audit. The oil reserves were calculated by volumetric method based on the geological model of the deposit, constructed using the IRAP RMS software package. The variability of the counting parameters was specified in the "Uncertainty" module, with the help of which it is possible to build a geological model with equiprobable realizations, having insufficient data on the main characteristics of the field.

When calculating the uncertainty, the variance by values was set for the following parameters: water-oil contact level, recalculation factor, porosity and water saturation coefficients. After computation and enumeration of possible implementations within the given parameters, the program generated the result in the form of three reserve values: P10 (probable), P50 (possible), P90 (proved). To compare the results of the reserves calculation, the resulting oil-saturated thickness maps were used to trace the distribution of geological reserves.

Based on the conducted research, it was revealed that input data and a different approach to the construction of the 3D geological model influence the final result in the distribution of the reservoir and the main parameters in the volume method formula. For a correct figure of hydrocarbon reserves (resources), it is necessary to use a multivariate distribution of counting parameters in the geological space of the considered object.

**Key words:** risk, probability-statistical estimation, Monte Carlo method, classification of reserves and resources of oil and combustible gases (RF Reserves Classification-2013), reserves and resources management system of liquid, gaseous and solid hydrocarbons (SPE-PRMS), comparison of domestic and international reserves assessment classifications

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A characteristic feature of the oil industry is an unforeseen change in oil prices. This is the basis of an uncertainty criterion that carries significant investment risk for oil companies (Knight, 2003). It is for this reason that such close attention is paid to risks. There are several categories of risk sources in the oil and gas sector in Russian science. Among them, it is customary to single out the following:

- geological risks;
- infrastructure risks;

- political risks;
- economic risks and others (Knight, 2003).

To date, there are two principal approaches to hydrocarbon resource estimation (oil and gas reserves estimation): deterministic and stochastic. Deterministic estimation is a selection of a single discrete scenario within the range of values that can be obtained as a result of probabilistic analysis. The second method implies the application of statistical distributions of parameters included in the formula of the volumetric method, where random realizations of each distribution of the counting parameter are multiplied in order to obtain a histogram of resources (reserves) for the evaluation object (Fig. 1) (Kelliher, Mahoney, 2000).

The generally accepted document in the field of probabilistic assessment of resources and reserves

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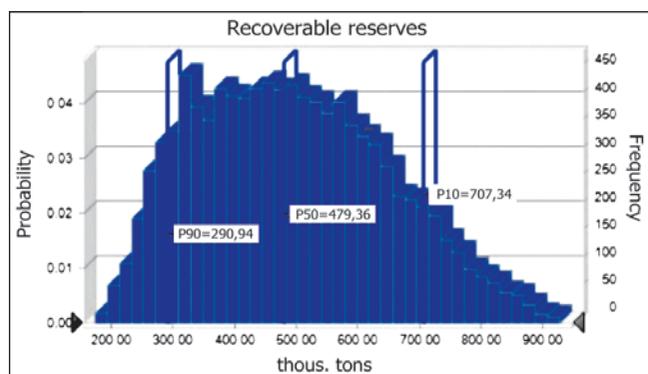


Fig. 1. An example of the histogram of the resources (reserves) distribution

calculation, including among Russian subsoil users, is the «Society of Petroleum Engineers – Petroleum Resources Management System» (SPE-PRMS). For the Russian Federation, a unified guideline regarding the principles of calculation and state accounting of reserves and resources is the methodical recommendation “Classification of reserves and resources of oil and combustible gases” (KZ RF-2013).

In these classifications, different methods of identifying a particular category of reserves (resources) are used. The difference between classifications is due to a number of reasons:

a) in estimation the proven reserves by PRMS, only existing (proven) at the time of the assessment of the field development technology reserves are taken into account. In practice of Russian companies, the orientation of both proven and promising technologies;

b) in estimation reserves according to international classifications, the average oil recovery factors are used, which are justified by analogous fields, while in the Russian classification they use final oil recovery factor values, including the use of secondary and tertiary methods for increasing oil recovery ;

c) in estimation reserves (resources), various methodical recommendations are used to single out one category or another, which leads to a difference in the value of reserves;

d) in practice of Russian companies, the assessment of resources and hydrocarbon reserves is usually made by deterministic methods, while probabilistic-statistical assessment methods are used abroad.

As practice work shows, for the Russian oil reserves classification, the basis of which is the volumetric method formula (deterministic method of reserves estimation), the overestimation of reserves (resources) without risk by categories of reserves (resources) is typical. This criterion is observed in the estimation of reserves (resources) by the Monte Carlo method, and in the case of multivariate geological modeling. Using the Monte Carlo method, it is difficult to take into account and reflect the internal connections between the parameters

of uncertainty. Firstly, the obtained distributions do not correspond to the existing knowledge about the object. They can be shifted in the direction of larger or smaller values, and also show more or less “variation”. Secondly, after assessing the reserves (resources) it is impossible to visualize the uncertainty in space, since the method does not take into account the physical volume of the object. As a result, it becomes necessary to apply the method of estimating uncertainty on models by key indicators. An advantage of the approach is that each implementation considers on an overall model that takes into account all available data and conceptual view of the estimation target. After estimating the uncertainty over a multitude of realizations, it is possible to visualize the results in the form of maps and geological profiles through the probability parameters.

Currently, there are many software tools that allow to carry out a probabilistic forecast with processing a large amount of information and perform a large number of iterations. A probabilistic assessment of the resource potential of promising objects was performed in the Resources Management System (RMS) “Uncertainty” software module, which allows identifying and evaluating the degree of uncertainty in the model and creating multivariate models taking into account the uncertainty.

In geological modeling, uncertainty is present at almost all stages: data import/export, correlation, structural modeling, averaging of well data, facies modeling, petrophysical modeling, reserves calculation, etc. (Sistema upravleniya resursami i zapasami... [Petroleum Resources Management System ...], 2007).

Using the various available properties of this module, it is possible to calculate many implementations of a particular model to substantiate decisions made at various stages of the geological substantiation of a field. Also, in addition to assessing the uncertainty of the model in which the same scenario is used, RMS “Uncertainty” allows creating many realizations, which makes it possible to evaluate the effect of each parameter on the simulation result.

Specifically, for the considered reservoir, the following ensemble of model implementations was selected:

- structural framework of the reservoir;
- wells with pointwise interpretation of porosity and oil saturation.

Let us consider the application of a multivariate (probabilistic) geological model at one of the reserve estimation target of the PJSC Tatneft field. The deposits of the Bobrikovskian horizon are composed of terrigenous rocks, the thickness of which varies from 1 to 13 m. In the sediments of the reservoir under study, two deposits of oil are found, which are associated with two different uplifts (Fig. 2).

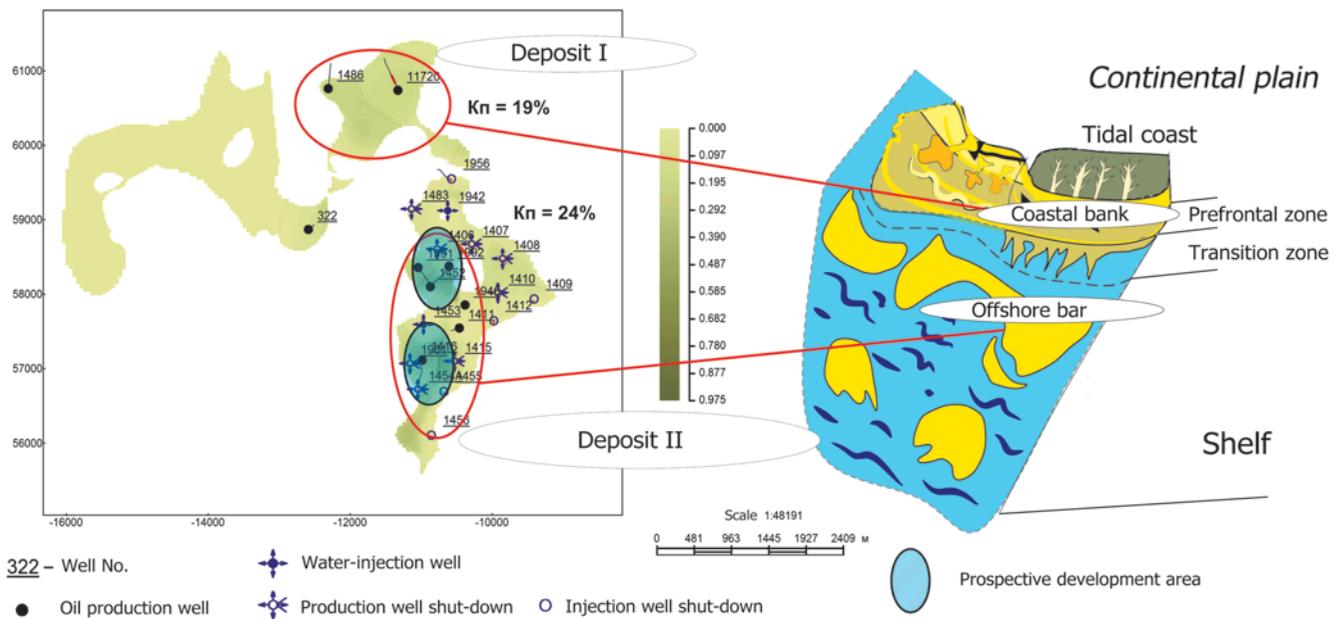


Fig. 2. Map of residual (mobile) oil reserves with the spatial distribution of sand bodies in the territory

According to the study conducted to recreate the conceptual model of the Sirenevsky field as a whole, the reservoir properties of rocks in the oil part of the field under consideration are different. The zone with a low value of the coefficient of porosity (19%) in the oil part is confined to the facies of a regressive longshore bar (deposit 1). The high value of the porosity coefficient (24%) is associated with the facies of the offshore bar (deposit 2). As a result, this heterogeneity is associated with the facial feature of the reservoir rocks of each of the deposits under consideration. Figure 2 shows a map of residual (mobile) oil reserves, on which the unevenness of sampling by area is well traced (Khisamov et al., 2017).

In accordance with the proposed formation concept of Bobrikovskian deposits on the territory of the field, the calculation of the probability-statistical model was carried out for each uplift separately.

### Task definition

Let us consider the use of the probabilistic-statistical module RMS “Uncertainty” on the example of one of the uplifts of the field under consideration (deposit II).

When the values of the calculated parameters are scattered, a multivariate geological model was constructed in which the dispersion of the values was set for the following parameters:

- Oil/Water contact;
- Formation volume factor ( $B_o$ );
- Porosity coefficient (Porosity);
- Coefficient of water saturation (Water saturation zone) (Sistema upravleniya resursami i zapasami...

[Petroleum Resources Management System ...], 2007).

Changing the settings of the calculation algorithms when constructing the model and the subsequent cross-assessment of reliability, we obtain different basic

variants with different predictions of oil-saturated thickness  $\Delta H_{oil}$  (Zakrevsky, 2009). Further, after setting the variables and scatter of variables, the number of realizations was set. Naturally, the larger the amount of the run that changes each coefficient, the longer and more accurate the calculation will be. In this case, the calculation was made for 200 implementations. The number of implementations depends on the power of the computer, but the final value of the implementations must ensure a lognormal distribution of reserves.

As a result of the generation of an ensemble of realizations, datasets are created: sets of 3D parameters, sets of net pay thicknesses maps and geological reserves obtained from them. Further, the probability of meeting of the reserves is calculated for each implementation separately.

According to the distribution in the diagram, the geological reserves of the multivariate model of the Bobrikovskian horizon of the considered deposit are as follows: P90 (proved) – 2.05 million  $m^3$ ; P50 (probable) – 2.2 million  $m^3$ ; P10 (possible) – 2.33 million  $m^3$  (Fig. 3).

The geological reserves of oil in the considered reservoir, built in a deterministic method, amount to 2.76 million  $m^3$ . In this method, volumetric parameters are given by static values. In other words, the geologist determined any parameter of the reservoir to within a tenth or hundredths of proportion. In this case, the calculated parameters of the deposit II have some variation in values with probability-statistical criteria according to the geological feature of the reservoir under consideration.

To compare the obtained geological reserves of the uplift, we used the values of the probabilistic-statistical assessment of reserves of the category P50 (as the most probable value) and the assessment of reserves

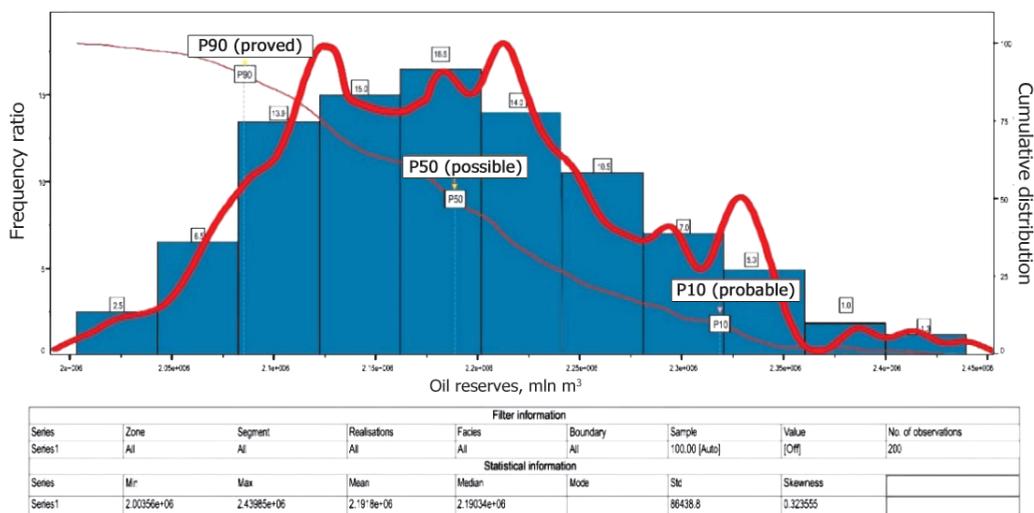


Fig. 3. Geological reserves by a multivariate (probabilistic) geological model of the deposit of the II East-Sirenevsky uplift of the Sirenevsky field

obtained from the deterministic model. According to the probabilistic-statistical assessment, the P50 reserves amount to 2.2 million m<sup>3</sup> of oil.

According to the deterministic model, the initial oil in place of hydrocarbons amount to 2.7 million m<sup>3</sup> of oil (which is 19% more than the probability-statistical model) (Fig. 4).

After estimating the uncertainty over a multitude of realizations, a map of net pay thickness was constructed for each of the realizations (P90, P50, P10). Also, a map of effective oil-saturated thickness for the implementation of P50 was implemented, generated after calculating parameters in the RMS “Uncertainty” module.

The areas of deposits, where oil-saturated rocks are widespread, were determined according to the calculation plan of the reservoir under consideration, which is limited by the external contour of oil-bearing capacity.

It is also necessary to take into account that the total volume of the initial oil in place in the probabilistic-statistical model is influenced by all the main volumetric parameters that are included in the implementation of a variety of realizations. Let us consider maps of net oil pay thickness constructed using various methods (Fig. 5).

In the end, when comparing the obtained data, several local zones were identified that contribute to the discrepancy in the statistics of geological reserves. For example, on both maps of net pay thickness, the limited elevation in the central part has different thickness lines (Fig. 5c). As a result, on the map constructed by the deterministic method, the value of the net-to-gross ratio is much higher than on the map of the probabilistic statistical 3D geological model.

This difference is due to the interpretation of drilling and geophysics data. In particular, in a deterministic assessment of reserves, the geophysicist determines the transition from the oil part of the reservoir to the water-saturated one with an accuracy of centimeters, on which the deposit area and the oil-saturated thickness of

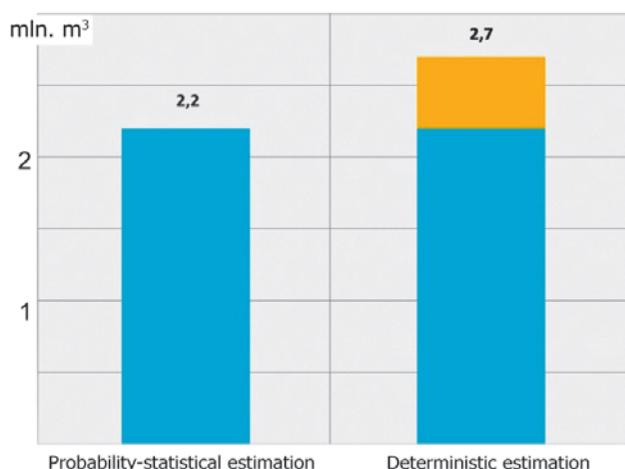


Fig. 4. Geological reserves of the Bobrikovskian horizon of a deposit 4 according to different methods of estimation, million m<sup>3</sup>

the reservoir depend. When determining the calculated parameters, due to the set of possible values, there is an error in the estimation. If we consider the assessment of reserves by the probabilistic-statistical method, then each element of the formula for calculating reserves under uncertainty conditions is given taking into account the variance, as described earlier. In this case, in the deterministic 3D geological model, the level of the oil-water contact of the considered uplift is taken according to the geophysical survey of wells and determined at an absolute elevation of minus 930 m out of 200 variations, which is 0.5 m less than in the deterministic 3D geological model (Table 1). This example is indicative of Fig. 5a, b and d.

**Comparison of the results of the reserves assessment of the Russian classification and the classification of PRMS. Reserves division into categories**

The allocation of categories of reserves by the considered area was carried out in accordance with the

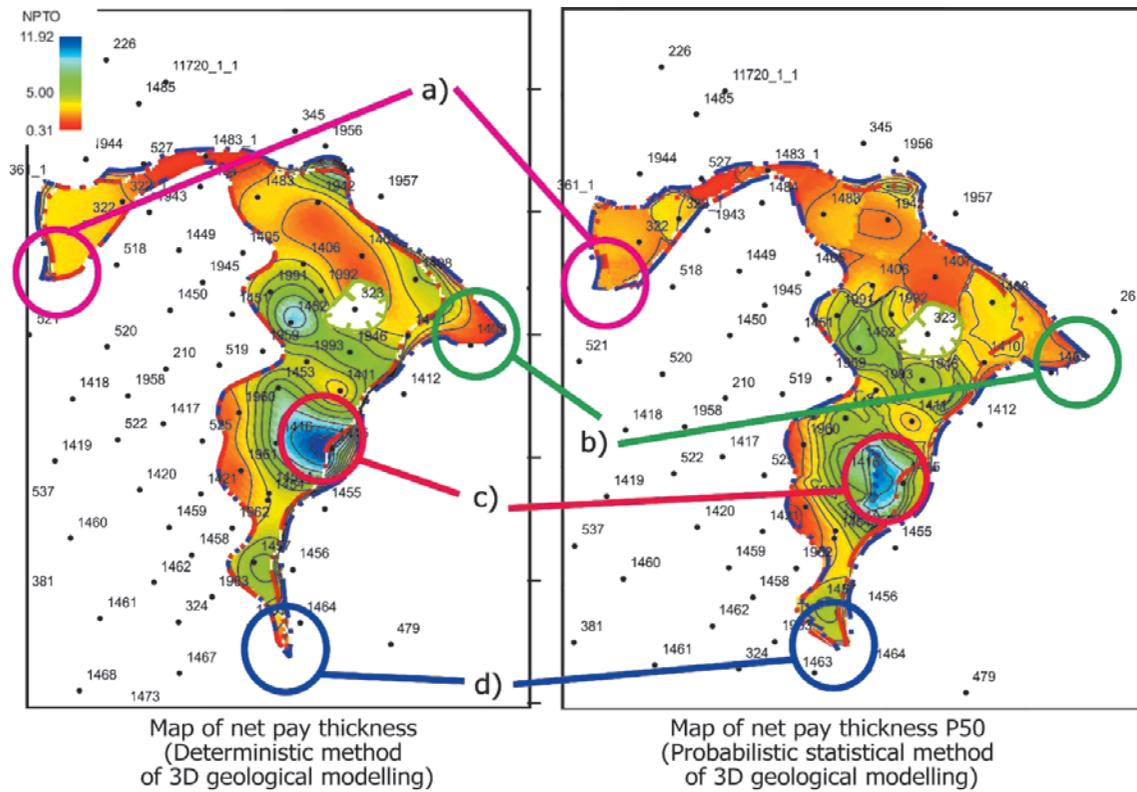


Fig. 5. Comparison of maps of net pay thickness of the Bobrikoskian horizon of the deposit 4

Method	OWC, m	Volume ratio	Porosity coefficient, un. fr.	Coefficient of water saturation, un. fr.	Initial geological reserves, mln m <sup>3</sup>
Deterministic	930	1,059	0,24	0,3	2,76
Probabilistic-statistical (P50)	929,5	1,051	0,234	0,29	2,2

Table 1. Estimated parameters of oil deposit II of the considered field

methodological recommendations on the application of the PRMS classification.

According to the current classification of PRMS, oil reserves of the considered horizon are classified as PDP, PDNP and PUD.

The reserves of the Pletnevsky uplift 1 are attributed to the PDP and PUD categories. The sediment-bearing capacity was established according to the logging data and confirmed by the results of the formation test in all wells. Industrial oil production is carried out in two wells.

The reservoir reserves of the II East-Syrenevsky uplift are classified as PDP, PDNP and PUD. The sediment-bearing capacity was determined according to the logging data and was confirmed by the results of the formation test in 18 wells. Commercial oil production was carried out in 17 wells.

According to the methodological recommendations on the application of the PRMS classification, the boundaries of the categories are placed at a distance of 150 m from production wells (Fig. 6b).

A comparison of the substantiation of categories and

indicators of reserves according to the new classification and the PRMS system, carried out in accordance with a probabilistic-statistical assessment, shows a significant divergence of results and the procedure for identifying categories (Fig. 6). In general, a comparison of all deposits of the Bobrikovskian horizon of the Sirenevsky field showed that the total reserves of the considered measurement facility, compared with the PRMS, differ by + 24% (Table 2). Thus, geological reserves by category A in relation to adjacent reserves according to the international classification (PDP and PDNP) differ by + 17%. Reserves of category B1, calculated according to the national classification, are significantly larger than stocks of PUD by PRMS (+ 55%).

Ultimately, when calculating hydrocarbon reserves, using different methods, the ambiguity results in the final result of hydrocarbon reserves. In other words, if the reserves are estimated using various methods, the total amount of geological reserves according to the national classification, which is based on the deterministic method, will be overestimated, due to the conservative approach to identifying reserves categories and in an

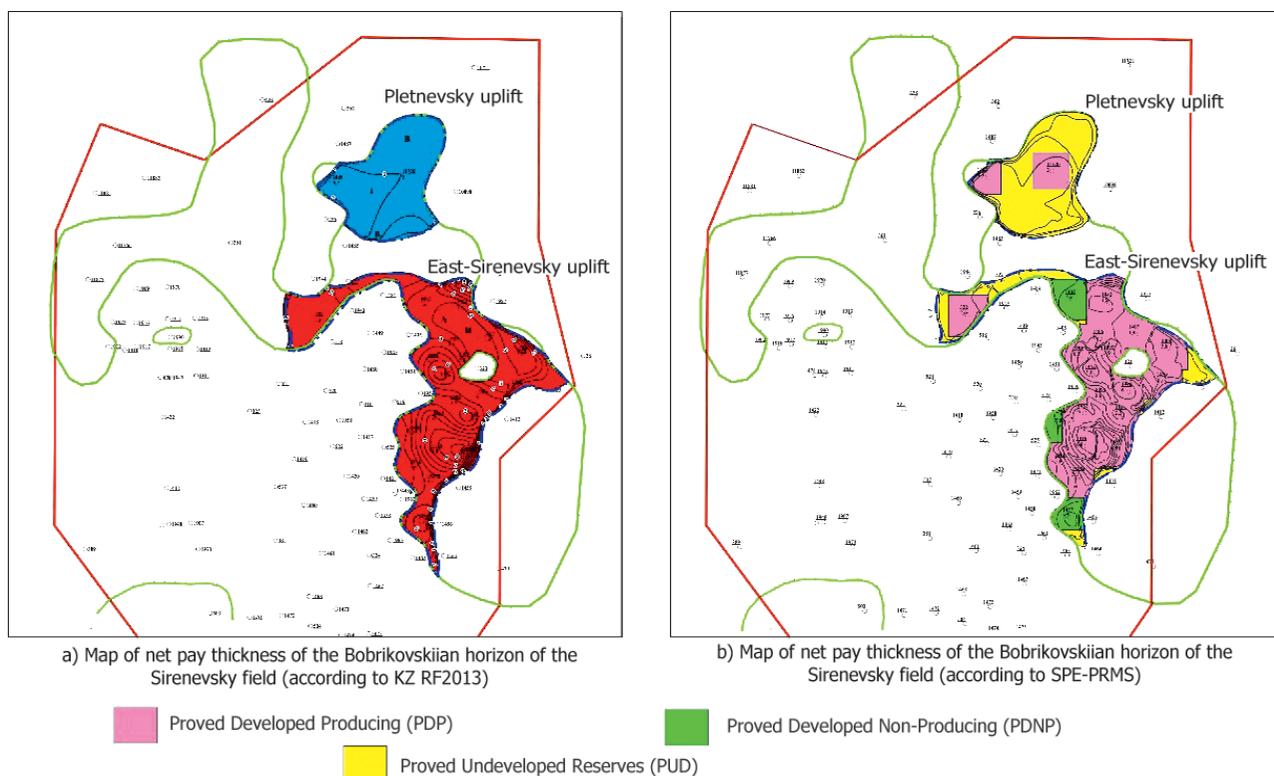


Fig. 6. Comparison of categorization of reserves according to the Russian classification (a) and according to PRMS (b)

Russian classification, 2013		Classification PRMS		Comparison of the KZ RF2013 reserves and PRMS reserves, %
Reserves category	Geological reserves, thous. tons	Reserves category	Geological reserves, thous. tons	
A	2766	PDP+PDNP	2282,4	+17%
B1	582	PUD	263,5	+55%
Total	3348		2545,9	+24%

Table 2. Comparison of the results of the estimation of oil reserves according to the Russian classification and the SPE-PRMS of the Bobrikovskian horizon of the Sirenevsky field

uncertain, ambiguous approach when averaging the calculated parameters bulk method.

Thus, a different approach in determining the accounting volumetric parameters influences the final result of the assessment of reserves, which causes a significant difference in the initial geological reserves of the considered calculation object. As the analysis has shown, for the selection of categories of reserves according to the Russian classification, the basis of which is the formula of the volumetric method, the overestimation of reserves (resources) relative to international classifications is characteristic. According to the results of the analysis performed in this work, the difference between the deterministic and probabilistic-statistical methods of the two deposits under consideration was 24%.

In order to rationally use the results of reserves calculation in the investment activities of the oil industry, it is necessary to standardize the approach in the formation of the government balance of reserves, which will contribute to the reduction of time and costs during the state examination of reserves.

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## Some aspects of modeling in the planning and analysis of development

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**Abstract.** The development of solutions, the selection of technologies to ensure the target levels of production and recovery of reserves require a reliable basis for research – qualitative data and adequate models that have acceptable predictive power. At the same time, the choice of approaches and tools for solving practical problems of development management should depend on the characteristics of the associated processes that determine the requirements for the result, resource constraints, the complexity of the description of the control object, and so on.

The authors of the article offer a review of the experience of applying the hierarchy of models within the technological chain of substantiation of operational decisions on the selection of geological and technical measures. The use of different-level models in the context under consideration makes it possible to obtain reliable estimates of the effects of activities in conditions of time-bound and labor-intensive constraints allocated to the solution of the problem.

**Keywords:** model hierarchy, selection of geological and technical measures, management of field development, technological decision support chains, down scaling

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The procedures for the selection and justification of geological and technical measures require periodic updating, changes and optimization of business processes. The influence of external and internal factors (deterioration of the structure of reserves, old assets, decrease in the efficiency of capital investments, etc.) prompts to look for more effective solutions, both in terms of cost optimization, and in terms of obtaining a cost-effective technological effect. The period of significant increment in additional production obtained through time-tested decisions inevitably ends, and in order to maintain production levels at the target level, research and development of new opportunities are necessary. At the same time, the development of solutions, especially for “complex” geological and technical measures (for example, aimed at additional recovery, development of hard-to-recover reserves), takes time; it is necessary to take into account that the maximum effect from the replication of technology can be obtained only after working through a whole complex of organizational, methodological, and technical issues.

To optimize the process of introducing new technologies, it is advisable to use the so-called proactive engineering support, which is:

- Formalization of procedures for the selection of new technologies;
- Adaptation and unification of the methodological support of the process;
- Making relevant changes in business processes;
- Development of auxiliary IT automation tools;
- Procedures for staff retraining and knowledge transfer.

Figure 1 shows a schematic mapping of the characteristic duration of engineering support stages in comparison with the potential effects provided by geological and technical measures of various levels of complexity.

It is obvious that adequate and reliable reservoir models are required as a basis for research in order to reproduce various scenario impact conditions.

Let us consider several levels of management of the field development process, where numerical experiments are required to obtain justifications for the decisions made (Fig. 2).

*Selection and justification of a field development strategy.* At this stage it is important to receive a fundamental answer about the potential profitability from the operation of the facility, to identify key design solutions. The stage is characterized by the creation

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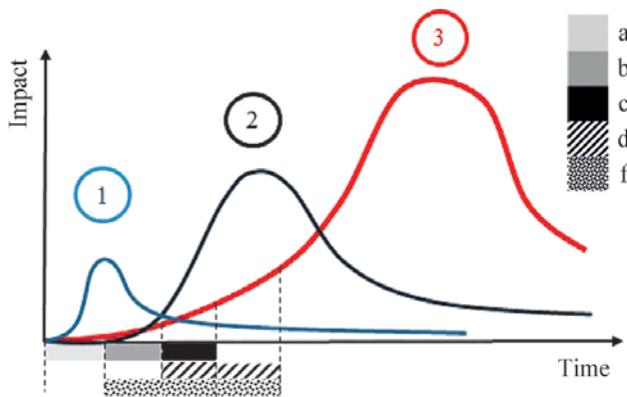


Fig. 1. Stages of engineering support for geological and technical measures of various levels of complexity. 1 – “Easy” geological and technical measures on optimization of technological potential; 2 – geological and technical measures to increase the productivity index of hydraulic fracturing, introduction; 3 – geological and technical measures for the development of non-drained reserves of vertically inclined wells, side-tracks. a – selection of technologies, b – development of methods, c – adaptation of processes, d – adaptation of tools, e – training of personnel

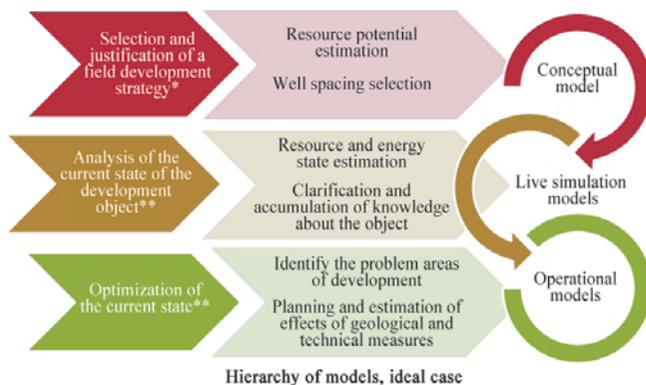


Fig. 2. Levels and objectives of development management. \* Strategic management level. \*\* Operational level of management (monitoring)

of conceptual hydrodynamic models, multivariate calculations, long-term forecasts.

*Analysis of the current state of the development object.* At this stage, monitoring of the implementation of design decisions, clarification and accumulation of knowledge about the object are conducted. The stage is characterized by the creation and adaptation of operational models reflecting the resource and energy state of the object.

*Optimization of the current state.* At this stage, problems that reduce the effectiveness of development management are identified, and comprehensive preventive measures are taken to influence the reservoir in the form of a program of measures aimed at achieving the target indicators. The stage is characterized by the creation of predictions of potential effects from exposure to justify the geological and technical measures.

Thus, ideally, a hierarchy of models with different

levels of detail should be created at different levels of development management, ensuring consistent simulation results that complement each other. Unfortunately, the expected value of the simulation results in reality can be extremely low. There are a number of significant, in our opinion, reasons for this:

- the complexity of the models used does not match the quality of the input data: high uncertainty and large errors in the initial information inevitable lead to erroneous estimates;

- the choice of methods, by which the problem is solved. takes place without a preliminary assessment of time and labor resource costs, and also without a clear idea of the degree of accuracy of the result, which will be enough to get a satisfactory answer;

- there are organizational gaps in the interaction of services that deal directly with the modeling processes (as a rule, these are dedicated project groups) with the services of potential end users interested in getting a practical result (these are development planning and production control services). The modeling process occurs independently and in isolation from the tasks associated with practical solutions for managing development.

In order to increase the effectiveness of model experiments, in our opinion, it is necessary:

- consider models as an integral part of the chain of analysis, justification and decision making;

- for each stage of analysis and decision making, use an adequate class of models that ensures the required accuracy of the result with acceptable time costs;

- ensuring the quality of the source data should be an obligatory stage of work, within which a reliable base for modeling is created.

Table 1 shows an example of the technological chain of measures justification and proposed acceptable level of detail for the models.

The effectiveness of the approach to the use of multi-level models is implemented today in modern oil and service companies. A number of examples of successful cases have been published in sources (Shigapova, Nugaeva, 2016; Khatmullin et al., 1999, 2015; Programmnyi kompleks «NGT Smart», 2010; Kostigrin et al., 2009, 2010; Khasanov et al., 2009 Khatmullina et al., 2014; Zagurenko et al., 2013).

Based on the analysis of the positive experience of using this approach, we can conclude about the viability of the practice of applying multi-level models in the context of business decision-making processes in the field of planning and analysis of development. At the same time, the principle of “down scaling” (a gradual increase in the complexity of models as we check the adequacy of the results obtained on simpler models) in many cases reduces the labor costs for creating and maintaining full-scale 3D models. Replication and adaptation of the approach to the use of the hierarchy

	Stages of technological chain	Function	Acceptable level of detail
1	Data collection and analysis	Check of data reconciliation	0-2D
2	Analysis of the current state of object	Creation of actual view of the current resource and energy state of the deposit	2D models Integral 3D
3	Problems diagnostics		
4	Decision making	Prediction of treatment effect	Detailed 3D
5	Experience accumulation	Post evaluation, error corrections	Hierarchy of models

Tab. 1. Technological chain of substantiation of operational activities

of models in different technological chains will allow, in our opinion:

- adjusting the data verification (reconciliation) processes to create a reliable decision-making base;
- optimizing the decision-making process in the field of oil production: improve the reliability of the estimates obtained while reducing the cost of decision development.

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# Conceptual geological modeling as a basis for the development of carbonate deposits in the Middle East region

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**Abstract.** When working with carbonate deposits, taking into account the geological features of their structure is necessary to understand the change in the dynamic properties of the formation at the beginning of the development. It helps to implement the most effective strategy from the selection of well types and to the identification of promising drilling zones. In this paper, an algorithm is presented to identify the main geological factors that have a significant influence on the approaches to field development and the confidence in production forecasting. An example is considered of the approach of LLC Gazpromneft-NTC to the study and prediction of properties by the example of one of the Middle East fields. This approach to modeling a complex carbonate field made it possible to obtain a conceptual geological and hydrodynamic model of the field. The created dynamic model increases the accuracy of the prognosis of the productivity of new wells and confirms high prognostic abilities following the results of drilling.

**Keywords:** geological concept, well productivity, carbonates, Maudud, Zagros

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## Introduction

The task of predicting the productivity of wells in carbonate reservoirs is always associated with high uncertainties due to the influence of many factors on reservoir properties of rocks both during sedimentation and during subsequent secondary transformations of the structure of the void rock formations.

The paper considers an example of the approach of the company Gazprom Neft Science and Technology Center to study and predict properties on the example of one of the fields in the Middle East. The main productive object is the Upper Cretaceous Maudud formation, 8 strata are distinguished within this formation (A, B, C, D, E, F, G, H) (Saad Z. Jassim, Jeremy C. Goff, 2006).

The deposits of the upper layers of the object under consideration (A, B, C) are sustained in area, have low variability of reservoir properties, which allows to predict the thickness and properties of rocks, the average error of the predicted thickness does not exceed 4%. The lower part of the formation (D, E, F), on the contrary, demonstrates the high heterogeneity and variability of reservoir properties in terms of area and vertical, which entails the need for facies and/or cluster analysis in order to improve the quality of the forecast.

The purpose of this work was to create a factual basis for confident prediction of the productivity of new wells.

Respectively the following tasks were solved:

- identification of the main drivers of rock conductivity for each of the strata of the formation;
- creation of the concept of geology;
- selection of a method for predicting the lateral distribution of properties in accordance with it.

Gazprom Neft Science and Technology Center has developed and successfully applied a standardized algorithm for working with carbonate reservoirs when analyzing data. It includes the analysis of petrographic studies, work with core data, interpretation of Wed and, as a result, the creation of a conceptual geological model (Idrisova et al., 2018).

The analysis of petrography includes an assessment of the genetic reasons for the formation of void space, the numerical determination of the degree of influence of secondary processes on the properties of the rock. The use of this approach in our case was complicated by a number of limitations in the initial data – secondary processes manifested in the rock are described at a qualitative level, there is no quantitative assessment.

It is worth noting a small number of core samples from non-key reservoirs; the strata B (145 samples) and D (510 samples) are most fully represented. In total, the core was extracted from three wells, with a total penetration of  $\approx 148$  m with a reservoir thickness of  $\sim 400$  m.

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### Lithological study of core. Evaluation of the role of secondary transformations

The pore space is represented by both intergranular and intragranular porosity, the presence of microfractures and dolomite crystals is noted (Fig. 1).

In order to assess the impact of structural (sedimentation) rock characteristics on reservoir properties, a comparison of the number of “grains” in thin sections was made with measurements of the porosity coefficient on cylindrical samples taken at the same points as the thin sections (Fig. 2). There is a trend of increase in the porosity of the rock with an increase in the ratio of grain/cement. Accordingly, the restoration of the sedimentation situation for the area under consideration implies an understanding of the most likely trend of property distribution over the area.

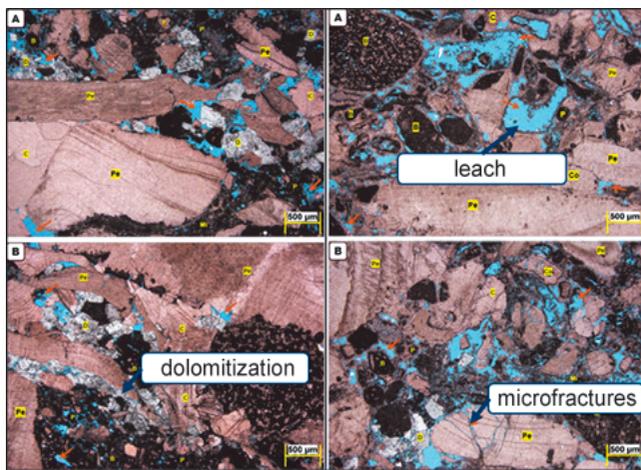


Fig. 1. Examples of thin sections

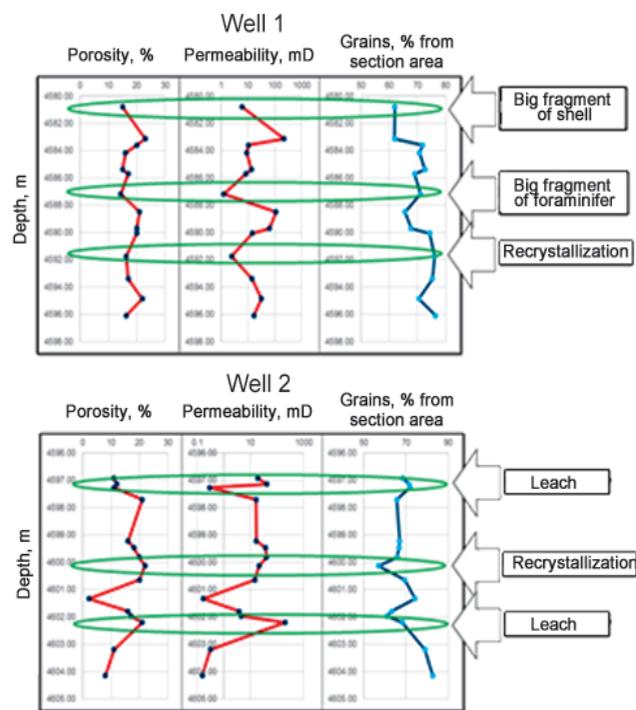


Fig. 2. Connection of primary sedimentation signs of rocks with their porosity

For some samples, the graphs show deviation from the selected trend. The main reason is the manifestation of secondary processes in the rock. Due to the lack of quantitative determination of the degree of their manifestation, conclusions were made at a qualitative level.

The visual study of thin sections of the D formation most clearly manifested dolomitization and leaching of the rock. If the first one had a negative impact on reservoir properties, then leaching affected positively. Secondary transformations probably took place in rocks with already good reservoir properties and due to leaching, improving the quality of the pore space. In zones with initially low reservoir properties, solution penetration was difficult, and in such rocks secondary transformations did not have such a serious impact.

### Creating a conceptual geological field models

Based on the general description of the core, as well as conclusions from the data of petrographic analysis, the sedimentation situation – the carbonate ramp – with rudist structures within its limits was restored (Fig. 3).

In accordance with the accepted concept, the correlation of the selected reservoirs was made by wells (Fig. 4).

According to the analysis of seismic data (spectral decomposition, Fig. 5a), zones for the development of anomalies are distinguished. Based on the conclusions about the conceptual structure of the layers, these anomalies are most likely to be zones of growth of organogenic structures (rudist reefs), which are characterized by increased filtration properties.

The analysis of hydrodynamic and field geophysical studies showed a significant difference in the filtration properties of the section.

The strata A, B, C (upper part of the section) are sustained along the section, however, they have permeability several times lower than the D and E

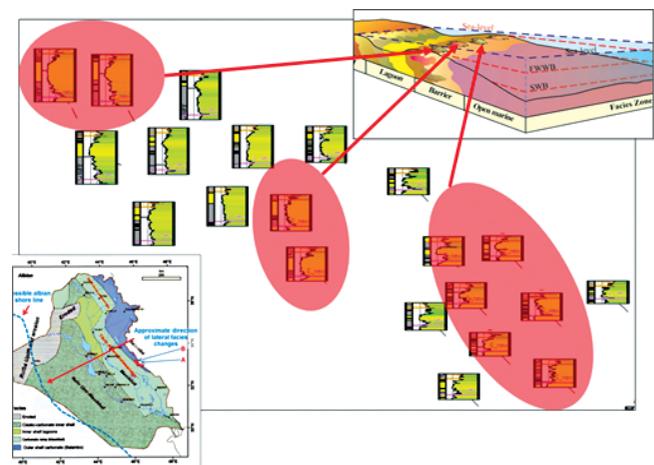


Fig. 3. The concept of the geological structure of the field (the areas of potential growth of organogenic structures are highlighted in color)

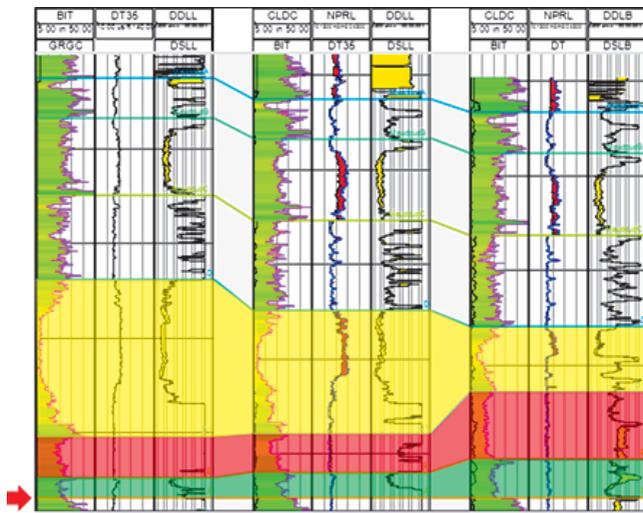


Fig. 4. An example of a reservoir correlation scheme (to the cross-strike)

layers, which is probably due to the smaller effect of the leaching process on the rock.

A comprehensive analysis of all types of data (core, logging, hydrodynamic studies, field geophysical tests) also showed that natural fracturing is weakly expressed and does not significantly affect the productive characteristics.

The results of the analytical work were used to create a geological model of the reservoir, which was then transferred for dynamic modeling.

During the analysis of seismic data, a relationship was established between the zones of cavernous development in the rock (confirmed by well data) and the attribute map of maximum amplitudes (Fig. 5b). This map was used as a trend in the distribution of the permeability field in the interwell space (Fig. 6). The approach used allowed us to obtain a good combination of the actual and model parameters of the dynamic model and did not require the use of additional settings (factors of permeability, productivity, etc.).

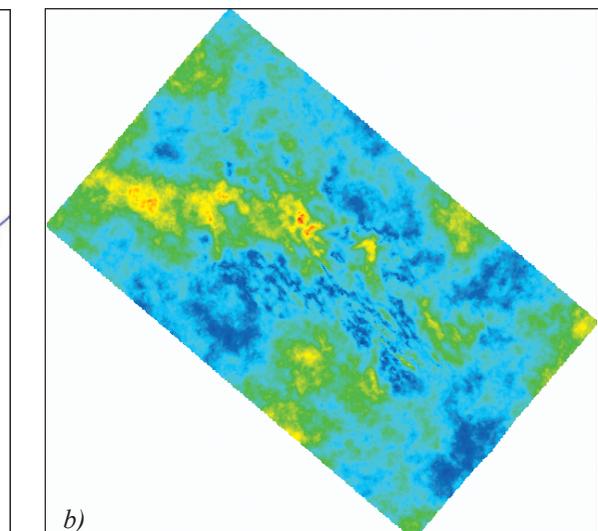
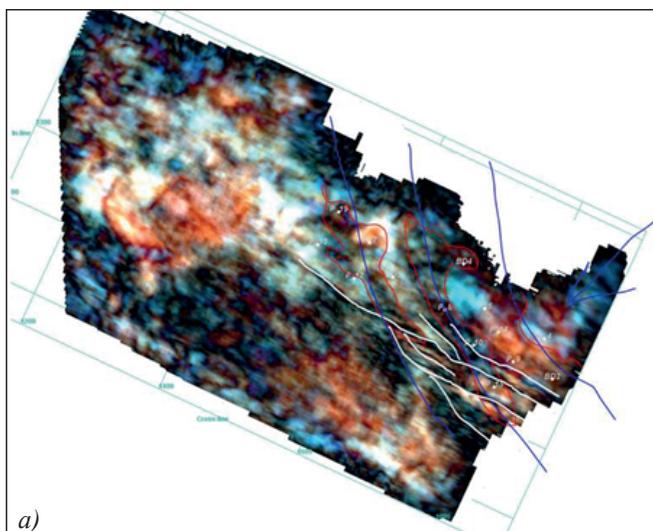


Fig. 5. Spectral decomposition

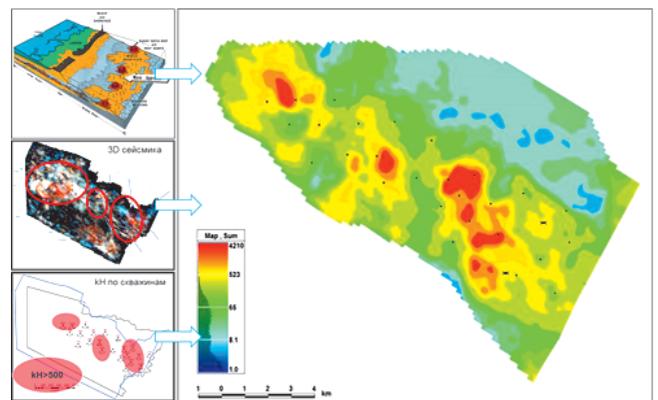


Fig. 6. The final map of the reservoir conductivity

**Conclusions**

A cross-functional approach to modeling a complex carbonate field allowed us to obtain a conceptual geological and hydrodynamic model of the field.

The created dynamic model increased the accuracy of the forecast of the productivity of new wells and confirmed the high predictive abilities based on the results of drilling.

The results obtained are recommended for replication when modeling other carbonate facilities of the company.

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# Hydrodynamic evaluation of the efficiency of flow deflecting technologies in conditions of formation of man-made filtration channels

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**Abstract.** The question is considered of the mechanism of waterproofing compounds at a late stage of development in zones of the formation that are different in geological heterogeneity. It is shown that man-made channels, which change the flow structure and distribution of mobile oil reserves, influence the process of filtration of injected water. The method of calculations is proposed, which allows to take into account the formation of channels and to determine their impact on the efficiency of flow deflecting technologies. To calculate the pressure, a hydroconductivity field is used at each point of the deposit, which is determined from the solution of the inverse coefficient problem.

**Keywords:** technogenic flood channels, water flooding cells, fixed flow tube method, short-term forecast, waterproofing composition, filtration flows, additional oil production, identification of hydraulic conductivity

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Despite the widespread introduction of flow-diverting technologies into the practice of oil production, the issue of the mechanism of their action in field conditions remains not fully understood. In many ways, this is agreed by the lack of methods for identifying and analyzing the most significant factors affecting the production of additional oil production. The article proposes a technological process based on the use of ready-made 3D geological and filtration models.

We also used data on geology, development, geological and technical measures and well testing (hydrodynamic studies of wells), stored as a database (Nasibulin et al., 2017). It was proposed to additionally build a model of the current energy states with identification of the hydraulic conductivity of the reservoir and the model of current tubes (Shelepov et al., 2017; Baushin et al., 2017), in which the possibility of working with man-made canals and blocking them with water insulating compounds was introduced.

The effectiveness analysis of the injection of water-insulating materials into the injection well, located in the center of the waterfloor element, allows us to obtain an uneven distribution of additional oil production

in the producing wells. The distribution of additional production, as a rule, is as follows. About half of the wells show an increase in oil production. The remaining wells give a slight negative result. At the same time, there are always wells that do not respond to the application of technology. The effect was observed already the next month after the event and lasted for 4-6 months. The Koch principle 80/20 is evident, according to which only 20% of the wells provide an economic effect and make it possible to cover losses in neighboring wells. This character of the effect can be explained by the influence of technogenic processes associated with the injection of a large amount of water of different hydrochemical composition. As a result, the mineral components of the reservoir are leached out and the weakly cemented solid particles are mechanically removed. For example, in the Upper Jurassic polymictic reservoirs, taken for analysis, content of carbonate material on average ranged from 10-15%. The destruction of carbonate cement under the action of water injection at high pressure drops leads to the formation of tubular channels with high conductivity. The presence of super-reservoirs with a permeability of up to 10 D in the section further contributes to an increase in geological heterogeneity. During the development process, new channels are formed between injection and production wells, which coincide with the direction of the current tubes, which have minimum dimensions and maximum filtration rate. Fig. 1 shows an example of the change in the accumulated water-oil factor in

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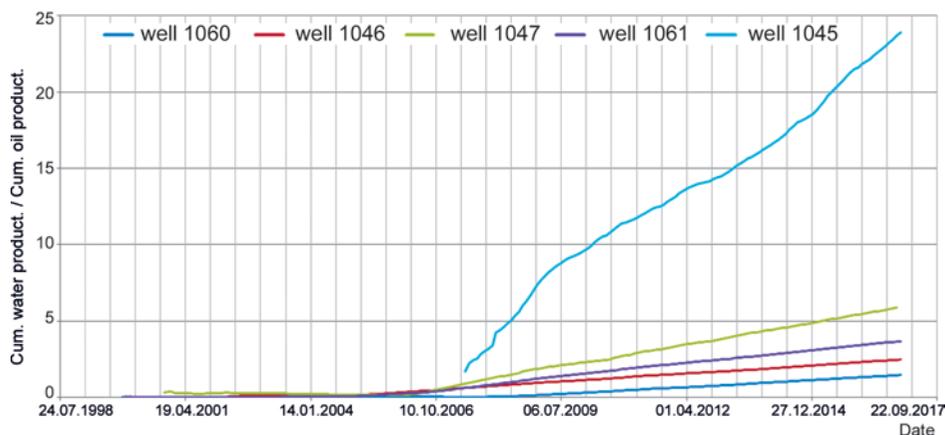


Fig. 1. The graph of the accumulated water-oil factor showing the well with the presence of technogenic filtration channel

one of the sections of the flooding, which includes five reacting wells. According to one of the wells, a sharp increase in water-oil factor is observed up to 24, while in the neighboring wells this ratio does not exceed 3-6.

A similar pattern of well irrigation can be traced in other areas, which indicates the presence of a wide network of technogenic filtration channels between injection and production wells.

The presence of water filtration channels is also noted for individual injection wells. So, according to well testing, more than 50% of the wells of the fields confined to polymict reservoirs, which are characterized by radial filtration with the presence of cracks. The presence of the filter channel is also indicated by the fact that the current injectivity has increased several times relative to the initial one.

Using full-scale 3D models to evaluate the effectiveness of flow diverting technologies is of interest only from a mathematical point of view. They use permeability values on geophysical data with low accuracy. In addition, due to the peculiarities of the calculation methods, the radial nature of the movement of water from injection wells to production wells is manifested. Estimated reduction of watering from the injection of waterproofing materials, as a rule, is observed only after 2-2.5 years, which contradicts the practical results. Full-scale models do not take into account the fact of anthropogenic filtration channels and do not contain information about their position in the section opened by the well. 3D models do not contain an apparatus that allows blocking water-flushed canals by pumping waterproofing materials. Therefore, at a late stage of development, a new calculation method is required, which is focused on the current parameters of the formations that have undergone significant changes in the original properties, due to the huge volumes of injected water. Calculations show that when switching from a 3D full-scale model to an integrated grid for different upscaling options, the value of geological and mobile oil reserves is maintained, and the averaging error of geological reserves is within 2%. When switching

to an integrated grid, the dynamics of development indicators also remain.

According to the accepted order of reception and examination of models, the three-dimensional model is used as a geological basis for hydrodynamic modeling. At the same time, it is required that it correspond to the calculation of reserves performed according to the current instructions of the State Reserves Committee for two-dimensional models. For this reason, for many deposits there is no need to use small 3D grids.

The energy regime of the deposit depends on the natural conditions and the water flooding system created and is "Engine" that defines the entire development process. For individual sites that are potential objects for the application of enhanced oil recovery methods, the energy regime determines the predominant direction of flow, flow through the boundaries of the sites, the activity of the outlined area and bottom water, and the nature of the interaction of wells.

When the pressure changes, the direction of the fluid movement changes. In addition, the energy mode also determines the nature of the interaction of the sampling zone with a gas cap. Therefore, great attention should be paid to identifying the relationship between sampling, reservoir pressure, the nature of the watering of individual wells and the presence of water outflow from the oil-bearing circuit. If the pressure rises, then the flow changes, the oil saturation changes. When analyzing the energy state of the reservoir, first of all, the flow rates, pressures and technical condition of the wells are linked. The calculation of the pressure field was carried out according to the equation of single-phase two-dimensional stationary filtration of a liquid, which can be written in the following form:

$$\nabla(\varepsilon \nabla p) = q, \quad (1)$$

where  $\varepsilon = kh/\mu$  is the coefficient of hydraulic conductivity,  $k$  is the permeability,  $h$  is the thickness of the formation,  $\mu$  is the viscosity of the fluid,  $p$  – pressure,  $q$  – intensity of sources and drain.

The boundary values in the outer region were set

within the outer contour of oil-bearing, as well as with taking into account that the deposit boundary may be limited by the lines of tectonic disturbances, the internal contour of gas caps, lines of substitution or wedging of reservoirs.

If we consider the oil reservoir as a whole, then the energy regime of the site is not only one of the main characteristics of the development process, but also the determining factor for the efficiency of current-diverting technologies. In this regard, to coordinate the production parameters for a given date of calculation in the work (Bulygin et al., 2001) it was proposed to apply a calculation scheme with the identification of the reservoir hydroconductivity field.

Identification of the field of hydroconductivity. To restore pressure at each point of the reservoir we have to know the field of hydroconductivity. One of the ways to determine the field of hydraulic conductivity is to solve the inverse coefficient problem (identification problem).

Different methods for solving the problem of identifying reservoir parameters can be divided into explicit methods and implicit methods. In the following, the implicit identification method is considered (Elesin et al., 2018), when the estimate of unknown parameters is iteratively improved so that the pressure values obtained by solving the direct problem coincide with the known pressure measurements. In this case, a multiple solution of the direct problem with different values of the identified parameters is required. The essence of the method is to minimize the residual function  $J$ , which is the sum of squared differences between the measured pressure values  $p^* = \{p_j^*\}_{j=1}^M$  characterizing the state of the reservoir, and the pressure values  $p = \{p_j(K)\}_{j=1}^M$  calculated using a mathematical model:

$$J = J(K) = \frac{1}{2} r^T r,$$

where  $K = \{\ln k_i\}_{i=1}^N$  logarithms of identifiable parameter values,  $r = (p_1 - p_1^*, \dots, p_M - p_M^*)^T$  is the residual vector,  $M$  is the number of pressure measurements,  $N$  is the number of identifiable parameters.

The minimization of the residual function is carried out by iterative methods, which are based on the construction of successive approximations of unknown parameters  $K^{n+1} = K^n + \Delta K^n$ ,  $n = 1, 2, \dots$  such that  $J(K^{n+1}) < J(K^n)$ , where  $n$  is the iteration number,  $\Delta K^n$  – increments of parameters. To stop an iterative process, two criteria are used:

1) Achievement of a given accuracy  $\varepsilon$  according to pressure measurements

$$\Delta p^m = \max_{j=1, M} |p_j(K^n) - p_j^*| < \varepsilon,$$

2) Slow convergence rate of the iteration process

$$J(K^n) - J(K^{n+1}) < 0.01 J(K^n) \text{ over 10 iterations.}$$

Different algorithms for determining the increments of  $\Delta K^n$  parameters lead to different minimization methods. These algorithms can be divided into three groups: direct search methods, gradient methods, various modifications of the Gauss-Newton method. In direct search algorithms, the minimization process is based only on the values of the function obtained for various values of the identified parameters.

As a rule, direct search methods have a low convergence rate and are rarely used in identification problems.

When constructing gradient methods at each iteration, it is necessary to calculate the derivatives of the function with respect to the desired parameters. Methods of steepest descent and conjugate gradients are widely used in identification problems. In the method of steepest descent to build successive approximations of unknown parameters  $K^n$ , the gradient of the residual function is used:

$$g = \text{grad } J(K) = \left\{ \frac{\partial J}{\partial K_i} \right\}_{i=1}^N,$$

(the sensitivity vector of the residual function relative to parameters). At each iteration, new parameter values are calculated using the formula:

$$K^{n+1} = K^n - \rho^n g^n,$$

where  $\rho^n$  is the step size determined from the minimum condition of the function  $J_\rho(\rho^n) = J(K^n - \rho^n g^n)$ . To find the minimum of the function  $J_\rho$ , various methods of one-dimensional minimization can be used.

The basis of various modifications of the Gauss – Newton method is the  $H = AA^T$  approximation of the Hessian matrix of residual functions, where  $A$  is the sensitivity matrix:

$$A = \begin{pmatrix} \frac{\partial p_1}{\partial K_1} & \dots & \frac{\partial p_M}{\partial K_1} \\ \vdots & \ddots & \vdots \\ \frac{\partial p_1}{\partial K_N} & \dots & \frac{\partial p_M}{\partial K_N} \end{pmatrix}$$

One of the modifications of the Gauss – Newton method, widely used in identification problems, is the Levenberg-Marquardt method. The vector of deviations in the Levenberg-Marquardt method approaches either the direction of the vector of the gradient of the residual function, or to the vector of deviations of the Gauss-Newton. The algorithm of the Levenberg-Marquardt method is written in the form:

$$K^{n+1} = K^n - (H + \mu^n E)^{-1} g, \quad \mu^{n+1} = \mu^n / 2,$$

where  $\mu^n$  is the Marquardt parameter,  $E$  is the identity

matrix. At each iteration, if the condition is violated:

$$J(K^n - (H + \mu^n E)^{-1} g) < J(K^n),$$

the  $\mu^n$  coefficient is doubled until this condition is fulfilled. The initial value of the parameter  $m_0$  is taken an order of magnitude greater than the maximum singular number of the matrix  $H$ .

It is believed that the solution to the problem of identification is obtained if the specified accuracy of pressure measurements is achieved.

In terms of the numerical implementation of geological field data of real objects, the identification algorithm should take into account and preserve the heterogeneity of the hydroconductivity field, due to the presence of tectonic faults, wedging lines and reservoir replacement.

Analysis of the results of hydrodynamic calculations in conjunction with the study of the nature of the irrigation wells and the state of the energy regime of the reservoir sites showed the presence of channels between the injection and production wells. On open cells of the nine-point system, waterflooding located on the border with the external contour of oil-bearing capacity, channels can be formed that control the outflow of water outside the reservoir (Fig. 2).

In areas confined to the oil-water zone, having contact with plantar and contour waters, the nature of fluid movement may be significantly different than in the central part of the reservoir.

A part of the waterflooding cells adjacent to the oil-bearing contour, at low sampling compensation values, injection is characterized by the inflow of formation mineralized water due to the external oil-bearing contour. Under these conditions, the formation of channels of filtration does not occur. Another part of the flooding cells is characterized by the outflow of pumped water out of the oil-bearing circuit. The significant role of the

filtration channels in the process of oil displacement is indicated by a steady increase in conductivity and permeability, which is not accompanied by an increase in the current reservoir pressure.

Conducting short-term forecasts based on flow tubes with fixed boundaries. Separate tubes of flow separated by lines of the lowest filtration rates emanating from the injection well form drainage sectors (so-called lobes). Each sector is characterized by the constancy of the law of conservation. This means that the reservoir parameters and fluid flow characteristics for each segment are unchanged for a time equal to 1-2 years, that is, from the beginning of the comparison base and several months after the effect ends. This time period is quite enough for the calculation of the basic variant and the variant with the use of flow-diverting technologies. A sectoral model using flow tubes, obtained from a 3D full-scale model, by transferring it to a 2D model of the flow state and the model of flow tubes can be used to calculate the design of the helium shield setting. The initial oil saturation values in flow tubes are determined by solving a full-scale problem for the current date. Next, the problem of two-phase filtration in flow tubes is solved with the calculation of the predominant movement of water through current tubes with high conductivity. Calculations are carried out taking into account approximately 500 flow tubes. The distribution of the current oil saturation in modeling the extrusion fronts and channels of high permeability is shown in Fig. 3. As channels of different widths, washed as a result of water injection into the injection well, for each drainage area, flow tubes of minimal length were taken (Fig. 3a).

The proposed filtering model allows us displaying a complex flow of fluid in the form of a combination of displacement fronts and water breakthroughs through the filtration channels (Fig. 3b). The presence of water supply channels is indicated by a sharp increase in the

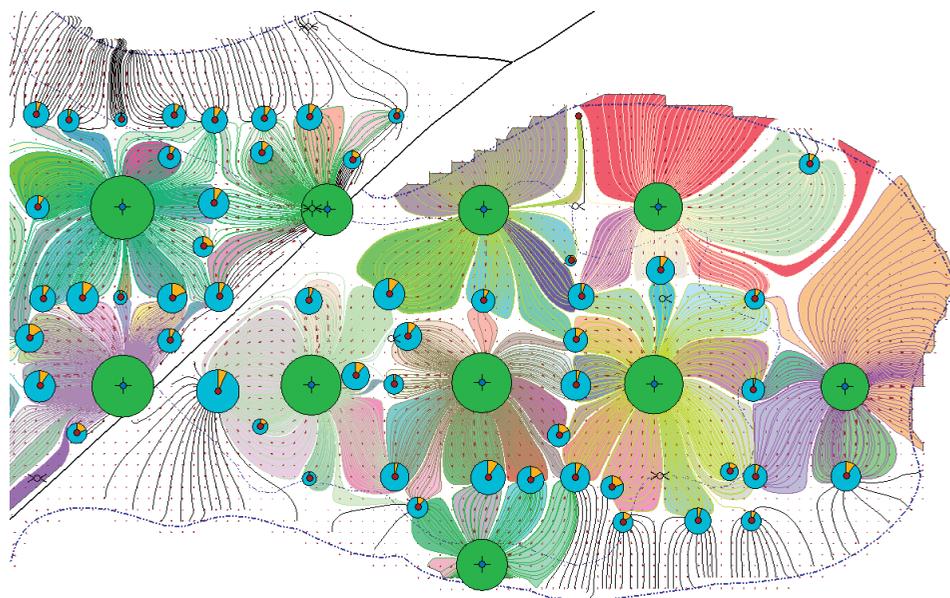


Fig. 2. Nine-point water-flooding cells with allocated drainage sectors

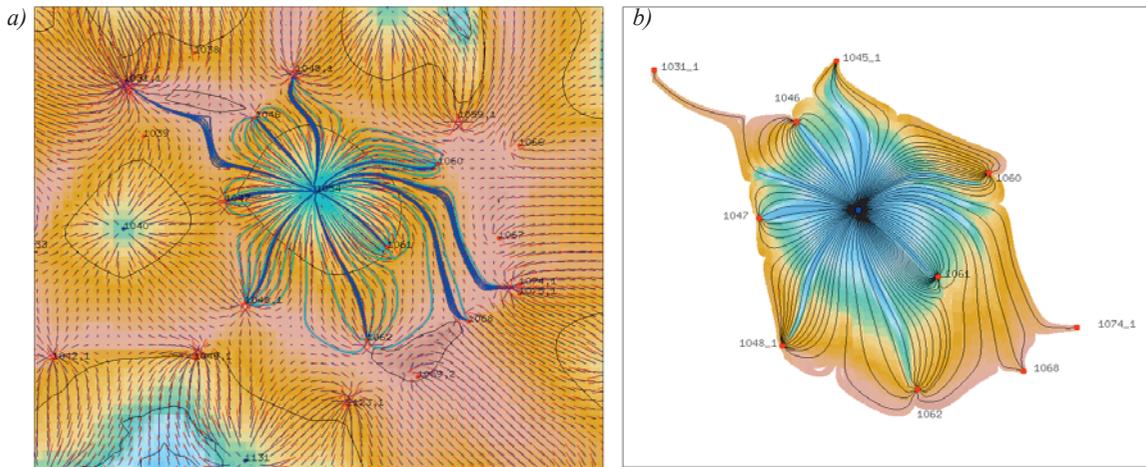


Fig. 3. Channel configuration (a) and saturation distribution (b) taking into account the channels

current injectivity of injection wells relative to the initial one, as well as the presence of production wells with high water withdrawals. The tubes are differentiated in length and width. It is possible to simulate different volumes of injection of a water insulating system, which will move mainly through wide channels (Fig. 4).

Through narrow channels with low permeability helium system will not go at all. The calculations should take into account that only part of the drainage sectors will be characterized by the presence of breakthrough filtering channels. Figure 5 shows the characteristic increase in additional oil production for the drainage sector, where the channels were isolated using injection of flow-diverting materials (Fig. 5), in which cross-linked polymer systems were used in the conditions of the late stage of development of a real field, where tens and hundreds of tons of oil were selected from wells, the deviation from the actual oil production curve calculated by the proposed method, the effects will be less significant (Fig. 6). At the same time, in the surrounding wells, where there are no technogenic channels for

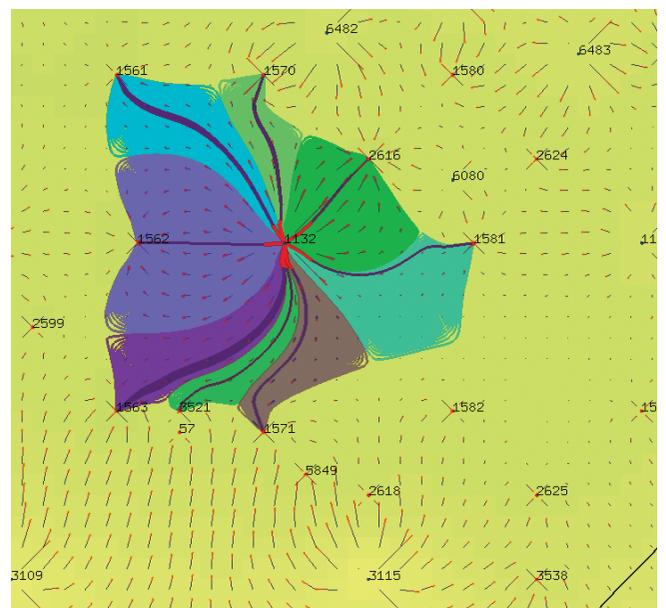


Fig. 4. Channels of different thickness washed in flow tubes of minimum length and injection of water insulating composition

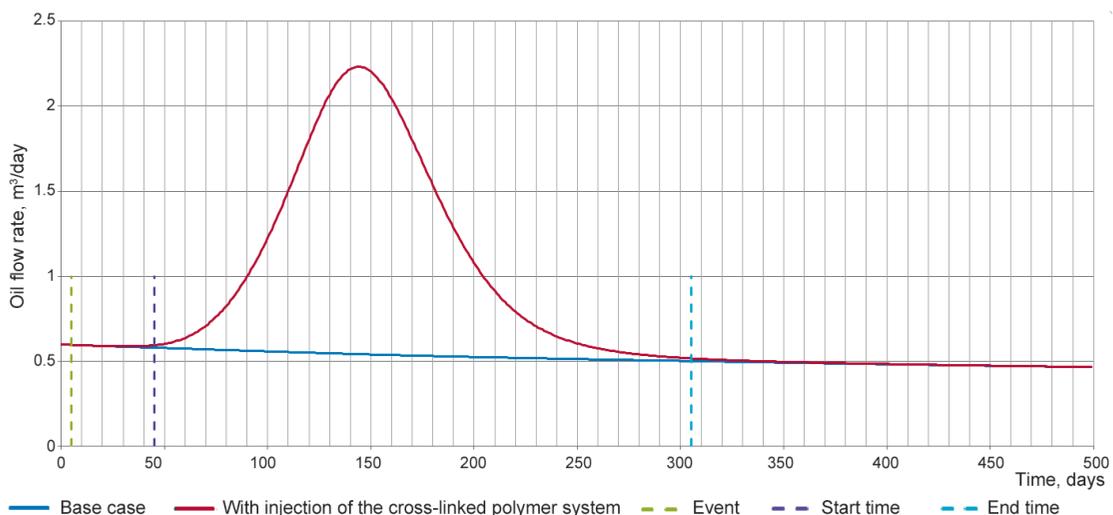


Fig. 5. The prediction of the flow rate of oil obtained from blocking the channel filtration. The blue line in fig. 5 shows the base case. The increase in oil production from injection of the cross-linked polymer system into the injection well is shown by a red line. Dashed lines indicate the time of the event (green), the start time (purple) and the end time (blue) of the resulting effect

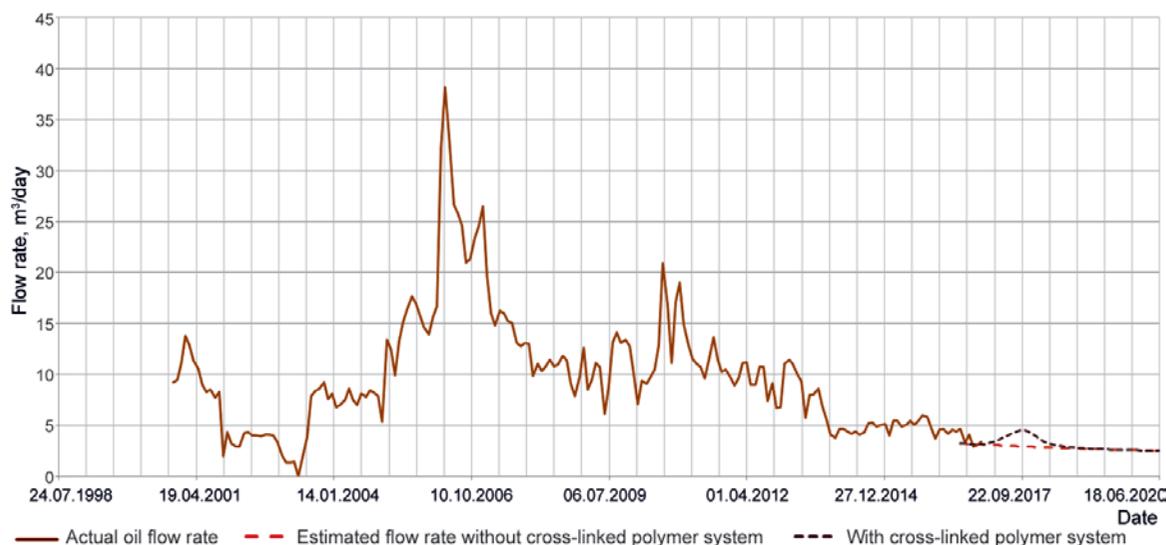


Fig. 6. Dynamics of oil production in modeling the injection of an insulating system

filtering, there will be no reaction to the injection of the water isolating system. The question about the features of the manifestation of the mechanism of action of water insulating compositions in various areas of heterogeneity and depletion of water-flooding reservoir is unexplored. Its solution is extremely important for determining the structural-mechanical properties and volume of injection of water insulating compositions that determine the resistance to erosion of helium screens. We should not forget about the strong influence on the formation of channels of geological features reservoir structure, which was not considered in detail in this work.

## Conclusions

1. Maps of permeability, hydraulic conductivity, isobars, filtration rates, obtained from hydrodynamic calculations, in combination with the study of the character of well watering and the energy state of the deposits, can be used to diagnose the presence of filtration channels.

2. Technogenic channels significantly change the structure of filtration flows and the distribution of mobile oil reserves within individual sections of deposits, which affects the efficiency of current-diverting technologies.

3. A calculation method is proposed to avoid common mistakes associated with limiting the duration of the effect in time and the localization of the effect in the area of the injection and the first row of the producing wells surrounding it.

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## Hydrodynamic modeling of thermochemical treatment of low permeable kerogen-containing reservoirs

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**Abstract.** The work is devoted to the effectiveness analysis of thermochemical method of intensifying the hydrocarbons inflow using binary mixtures based on ammonium nitrate in the development of low-permeability reservoirs of unconventional hydrocarbons represented by petroleum-derived kerogen-bearing rocks. The concept of the research is aimed at determining the principles of treating kerogen-bearing layers and the creation of new scientific, methodological and technological solutions to increase the efficiency of developing deposits of these unconventional hydrocarbon reserves. Some properties of oil source formations located on the territory of the Russian Federation are generalized and structured. The results of investigations of the thermal treatment on rocks of the Bazhenov formation are generalized.

The authors present the principles of mathematical modeling of thermal and chemical processes, allowing to take into account the geological and hydrodynamic features of kerogen-containing rocks. We have described a mathematical model of the thermogas chemical treatment with the use of binary mixtures. The calculation results of the treating the field with highly viscous oil are given.

Based on the calculation results of thermal-gas-chemical treatment (TGCT) of low-permeable reservoir with highly viscous oil, a positive effect was obtained. Therefore, the authors conclude that the TGCT method, along with the search for other methods for the development of kerogen-containing reservoirs, can be considered promising and possibly more optimal than the thermal and chemical methods used.

**Keywords:** unconventional sources of hydrocarbons, kerogen, kerogen-containing rocks, thermochemical methods, mathematical modeling, generation of hydrocarbons

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Specific strata, now called the Bazhenov formation, have been known for almost 60 years – in 1959 they were mentioned by F.G. Gurari in relation to the Priobsky field, geographically linked to the Bazhenovo-Sargatsky district of the Omsk region. At present, about 70 fields in Russia are referred to as oil and gas source in the Bazhenov formation. The rocks of the stratum are geographically located in Western Siberia, occur at a depth of 2-3 thousand meters and have a thickness of 10 to 100 m. At the same time, these layers are characterized by a small amount of mobile oil, low reservoir properties, while possessing a rather high content of organic matter – kerogen (about 14%, according to (Deliya, 2015); 5-40% according to (Kuz'min, 2015)), as well

as abnormally high reservoir pressures, which are 1.5-2 times higher than normal levels of hydrostatic pressures (Tarasova, 2012) and temperatures which are in range of 100-134°C. The Bazhenov layers were considered an impermeable cap of more productive formations and were considered ineffective in terms of operation. In the past 20 years, in connection with the development of new technologies and the success of the development of “shale oil” (oil of low-permeable tight rocks) in the United States and tar sands in Canada, the development of Bazhenov formation layers is no longer considered unpromising. However, the complex geological structure, the pronounced inhomogeneity of layers with different mineral compositions, permeability (even impenetrable), makes each section essentially unique in terms of the choice of development method. The presence of irregular clay interlayers (mainly mixed formations of hydromica) gives a significant anisotropy of the layers, while the relationship between the clay content and the percentage of kerogen does not have a

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correlation connection (Kuz'min, 2015). The complexity of the structure of the Bazhenov strata is also due to the presence of the so-called dual porosity – open porosity and fracture “filled” with free mobile hydrocarbons and anomalously low porosity of the kerogen matrix itself. Usually it is believed that the porosity and permeability of kerogen is so small that the matrix is usually assumed to be impenetrable. However, recent studies show the dependence of both the open porosity of the core and the porosity of kerogen on the thermal maturity of kerogen, which differs significantly in different areas (Gil'manov, 2015).

The deposits of the Bazhenov formation, which have kerogen in the solid structural matrix, are conventionally referred to the group of so-called unconventional fields and even combined into a general subgroup of shale oil fields. Although fundamentally, it is a completely different type of hydrocarbons (type of kerogen) than similarly called fields, for example in the USA. Only small values of reservoir parameters and development complexity are related to them.

Now a lot of theoretical studies are devoted to the study of “Russian shale oil” fields, although, of course, there is already a rather long history of interest in studying kerogen in Russia, while the following have been established. It is inefficient to extract hydrocarbons from these layers by conventional methods, but laboratory experiments show the ability to activate the generation of mobile hydrocarbons from solid kerogen under certain conditions: temperatures of about  $T = 300^{\circ}\text{C}$  make it possible to start the generation mechanism, and at temperatures above  $T = 700^{\circ}\text{C}$  we can expect generation mobile hydrocarbons are actually in real time.

It should be noted that it is extremely difficult to transfer laboratory techniques to the practice of developing real deposits. An important factor here is the diversity of the geological structure, occurrence conditions, reservoir conditions for various deposits containing kerogen. In addition to the Bazhenov formation, there are several oil source strata in Russia. In the northeast of the Siberian platform, the Kuonam formation is located, containing alternating marls and argillites with an organic matter content of 0.1-19.5% (Zueva, 2012). The oil resources of the Kuonam formation range from 700 million tons according to VNIGNI (2011) to 15,000 million tons according to SNIIGGiMS (2017). The most studied Domanic formation is located on a large area of the eastern part of the East European Platform, with a kerogen content of about 5%, on the territory of which about 10 oil fields were found with a total volume of recoverable oil reserves of about 27 million tons (Prishchepa et al., 2014). Mining is not conducted. In the regions of Ciscaucasia and the North Caucasus, the Khadum

formation is widespread, which partially has oil source areas with an average organic content of about 2%. The sediment thickness varies from 25 to 90 m (Egoyan, 1969). According to the Rosneft company, the open oil reserves of the Khadum formation are estimated at about 11 million tons, and there is almost no production.

Also in Ciscaucasia, at the depths of over 5 km, the Kums kian horizon is located, containing sapropel organic matter in concentrations of 0.5-5% (Distanova, 2007). Oil accumulations of this formation are predicted in the Crimean-Caucasus region, including the Tuapse Trough, poorly studied from a geochemical point of view. The Pilengsky formation of the Miocene age, with a capacity of 100 to 500 m and more, is the main productive horizon on Northern Sakhalin (Gladenkov, 2002). In the south-east of the Siberian platform, the Malginsk formation of the Middle Riphean is widespread. The content of organic matter in rocks varies from 0.04 to 12.69%, the average value is 4.37% (Dakhnova et al., 2013).

Table 1 shows the main properties of the described deposits – data on the location of formations, the type of rocks, approximate age, thickness of rocks, reservoir temperature and fraction of organic matter. Creating an effective method for extracting hydrocarbons from the formations described is more associated with the ability to activate the generation of mobile hydrocarbon fractions from the kerogen matrix directly in the formation.

A lot of theoretical and experimental works are devoted to the issue of kerogen hydrocarbons generation. The authors note that, in addition to elevated temperature, other factors are of great importance in order to achieve the process of in-situ conversion of kerogen to mobile hydrocarbons: the presence of cracks in the structure of the pore space, providing migration paths of the resulting decomposition products of kerogen (Korovin et al., 2014), the presence of catalysts, uniaxial geostatic pressure (Nesterov et al., 1993), water (Vorob'ev et al., 2007), hydrogen (Kayukova et al., 2011), the mineral component of the rock (Kokorev, 2010), and others.

Most researchers agree on the application of thermal methods of exposure to kerogen-containing rocks. Summarizing the results of studies of thermal effects on kerogen-containing rocks, it is necessary to indicate the following intra-layer processes revealed: the appearance of mobility of the bituminous components of fluids (viscosity reduction), which initially saturate the formation; generation of additional mobile hydrocarbons from the kerogen matrix of the rock, as well as the associated increase in porosity and the formation of additional fracturing.

The intensity of these processes depends not only on the thermobaric state of the reservoir system, but also on a number of particular factors that individualize a

Formation	Location	Type of rocks	Age	Thickness, m	Area, km <sup>2</sup>	Fraction C <sub>org</sub>	Temperat. of format.
Bazhenov	Western Siberia	Carbonate-clay-siliceous deposits	Late Jurassic	20-60	>1 mln	14%	80-140°C
Kumsk	Ciscaucasia	Marls, clays, bituminous shales containing large fish scales	Eocene	40-60	40-50 thous.	0,5-5%	82-100°C
Khadum	Ciscaucasia	Clays with interlayers of marls and siltstones	Oligocene	25-90	450 thous.	5%	40-180°C
Domanic	Eastern European part of Russia	Clay-carbonate rocks	Late Devonian	20-100	400 thous.	Domanicoids (0,5-5%), Domanicites (5-25%)	30 °C
Kuonam	East Siberia	Domanicites, calcareous-clay and calcareous-siliceous shales, marls, clay limestones	Early Cambrian	20-70	114 thous.	0,1-19%	n/d
Pilengsky	North Sakhalin	Fine interbedding of pelitomorph siliceous and clay-siliceous rocks with interlayers of tuffs, sandstones and aleurolites	Miocene	100-500	20-30 thous.	0,3-2,9%	n/d
Malginsk	South-East of the Siberian platform	Variegated fine-limestone, turning into gray, sometimes bituminous limestone	Paleozoic	100-400	30-40 thous.	0,04-12,69%	n/d

Table 1. Basic oil source formations of Russia

particular area, for example, the presence of zones of anomalous cuts (alternating layers), the composition of the skeleton of the rock (the ratio of bituminous mudstones and sandy-aleurite layers, dolomitized sandstones, shale, etc.), the presence in the pore space of bound water. Difficulties in the study of fields are due to the fragility of the rocks, the destruction of the core during selection, and the change in reservoir properties under non-reservoir conditions. The question of the kinetics of transition of a kerogen to a mobile state also remains an urgent issue.

The largest number of experiments is devoted to pyrolytic decomposition (Rock-Eval method), which makes it possible to determine the yield of various components at a certain temperature level: at 100°C free gases are emitted from C1 to C4, at a temperature of 300°C the first peak S1 – characterizes the transition in the gas phase of liquid hydrocarbons C5-C7 and part of asphaltenes, the second peak of S2 is recorded at T = 600-850°C with the release of tar-asphaltene substances and kerogen, the following peaks S3 and S4 correspond to the release of CO and CO<sub>2</sub> due to

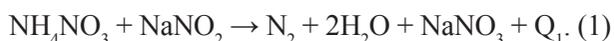
combustion of the residual th carbon. In this case, it is the peak S1 that characterizes the fraction of kerogen that has passed into the mobile state, and S2 – the part that remained in the solid state (unrealized potential). The sum S1+S2 is actually called the generation potential and reflects the maturing property of source rocks from various fields. On the basis of this technique, the source rocks are classified according to generation ability. However, using this method it is impossible to obtain dynamic links between process parameters. In this paper (Gaiduk, 2009), a new approach to the description of kinetics was proposed, which allows calculating the thermodynamic characteristics of not individual components, but kerogen in general, and to calculate the thermodynamics of any stages of kerogen catagenesis on this basis.

The process of decomposition and transformation of kerogen leads to changes in the structure of the rock. This fact imposes the need to use functional interdependencies of parameters such as porosity, permeability and the number of additional mobile hydrocarbons in the model of the kerogen-bearing formation. The most well-known

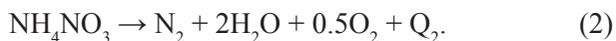
and frequently used function that relates porosity and permeability is the Kozeny-Karman formula.

However, the peculiarity of kerogen-containing rocks in the form of their low permeability and tendency to cracking under thermal influence does not allow the latter dependence to be applied, but requires further clarification of the method of describing a significant increase in permeability with a slight change in porosity. At small porosity values, the linear Kozeny-Karman function can be replaced by the exponential dependence of the permeability drop on porosity. For Bazhenov formations, the study of core material showed the irregularity of the functional dependence of porosity – permeability (Kuz'min, 2015).

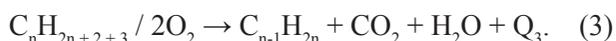
The lack of correlation due to a wide range of fractional composition, bulk density and chaotic fracturing and cavernosity. The choice of the method of influence on the kerogen-bearing strata currently remains open. The works (Dieva, 2015; Kravchenko et al., 2016; Kravchenko et al., 2018) gave a detailed review of approaches to the practical implementation of development projects for fields containing kerogen. The authors' work showed that the temperature levels required for the active generation of hydrocarbons from the kerogen matrix can be efficiently and safely for mining equipment obtained by decomposing solutions of explosives in the formation. The fundamentals of the thermogas-chemical exposure technology based on aqueous solutions of explosives were developed more than 15 years ago (Aleksandrov et al., 2004) and have been significantly modified recently (Alexandrov et al., 2016; Vershinin et al., 2016). The essence of the thermogas-chemical exposure technology (TCET) method is to inject a solution of explosives into the formation and stimulate explosives to decompose. The authors suggested using for this purpose a saturated aqueous solution of a binary mixture (BM) – ammonium nitrate mixed with sodium nitrite. Schematically, the interaction reaction solutions can be represented as follows (Mel'nikov, 1987):



As a result of this reaction, heat of 4688 kJ per kilogram of nitrate is released. At temperatures above 200°C in the presence of chlorine ions, thermal decomposition of nitrate occurs:



In reaction (2), 2650 kJ are released per kilogram of nitrate (Mel'nikov, 1987). The released oxygen and heat initiates the oxidation of residual oil in the reservoir:



Reaction (3) also comes with the release of heat, which is estimated at 2380 kJ per 1 kg of nitre throughout the chain of reactions (Aleksandrov et al., 2007). The

total heat dissipation as a result of all reactions of solutions of a binary mixture lies in the range from 4688 to 5030 kJ of heat per kilogram of nitrate.

The temperature reached in the reaction zone will depend on the concentration of nitrate, residual oil saturation, injection rate and external conditions. Fig. 1 shows the results of laboratory studies of temperatures achieved by the decomposition of a binary mixture at different concentrations of explosives in water (made in JSC GosNII CRYSTAL). Numerical simulation of the process of heating the reservoir in the near-wellbore region with different BS injection volumes showed that the temperatures reached depend on the concentration of nitrate in the BM, the water saturation of the solution, residual oil saturation, injection rate and external conditions. Fig. 2 shows the calculated temperature levels at different distances from the well, depending on the volume of injection of explosives (in tons).

As follows from Fig. 1 and 2, the injection of explosives allows reaching reservoir temperatures sufficient to initiate the reaction of decomposition of kerogen. By varying the salt content in the solution and the volumes of BM injected solutions, it is possible to achieve the required temperature levels in the near-wellbore region.

BM injection technology seems to be the safest compared to other explosives by regulating the energy component of the decomposition of ammonium nitrate by selecting the appropriate concentration of explosives in an aqueous solution and special inhibitors of chemical reactions. The technique is successfully used in oil fields at a late stage of development. Details of the description of the injection method based on ammonium nitrate mixtures, the decomposition of which in the reservoir leads to an increase in temperature due to the exothermic reaction of decomposition of explosives, reduced fluid viscosity and enhanced oil recovery are described in detail in (Volpin et al., 2014; Kravchenko et al., 2018; Vershinin et al., 2018). This technology allows creating in the reservoir a zone of high temperatures of up to 500°C, actually necessary for the generation of liquid hydrocarbons from kerogen.

The work (Kravchenko et al., 2016) substantiates the possibility of the effective application of the thermogas-chemical effect on the kerogen-bearing rocks of the Bazhenov formation.

At this stage of the theoretical study, the authors took into account the diversity of laboratory and field experiments with kerogen, core materials of kerogen-containing formations and created a mathematical model that allows one to numerically evaluate the nature of such an impact on unconventional low-permeable reservoirs, including kerogen-containing. The model allows to take into account the generation of heat in the zone of explosive decomposition, the change of thermobaric

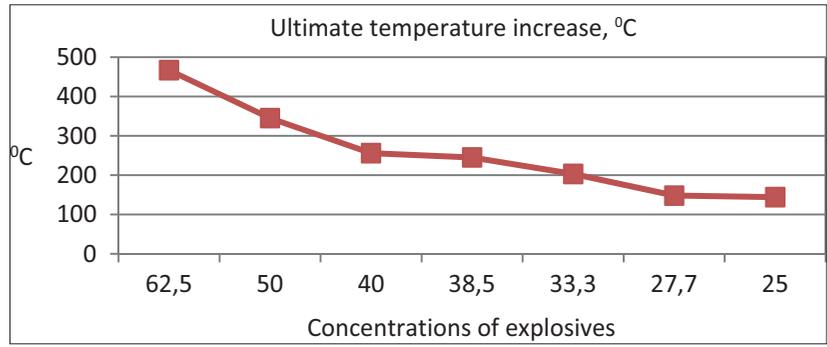


Fig. 1. The level of temperature increase during the decomposition of BM  $NH_4NO_3/NaNO_2$

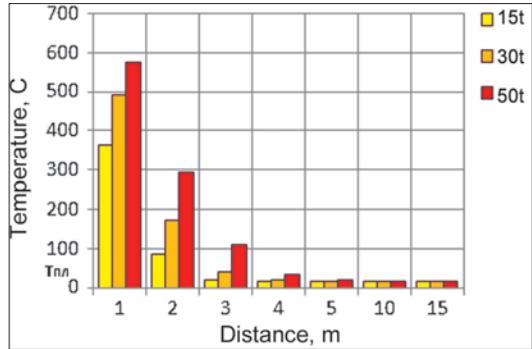


Fig. 2. Estimated levels of temperatures reached in the bottomhole zone at various volumes of BM  $NH_4NO_3/NaNO_2$  injection

parameters, the transformation of the reservoir itself due to changes in its structure, including the decomposition of the solid phase (kerogen) with the release of additional mobile hydrocarbons.

Fig. 3 schematically shows an element of the computational three-dimensional region that simulates the region of a saturated reservoir bounded by an impermeable roof and bottom. The figure shows the areas of sequential injection of various fractions of working fluids in the process of organizing the TCET and the formation of the reaction zone during the decomposition of explosives.

Mathematical modeling of TCET processes is carried out in several stages. At the first stage of modeling this

process, the task of pumping the necessary volumes of reacting and buffer substances is calculated according to the rules of GIS technology at a particular field and candidate well. Analysis of the field saturation distribution fields allows setting the time and place for the thinning of the buffer water zone separating the reacting substances and, accordingly, the location of the reaction zone of chemicals and the thickness of the interaction zone of the reacting substances (Fig. 3).

Hereafter are some of the results of calculations describing the organization of TCET in a 25-meter-thick cylindrical reservoir to the regulations that involve the injection of a binary mixture with a volume of 20 m<sup>3</sup> and the following squeezing water in a volume of 170 m<sup>3</sup>.

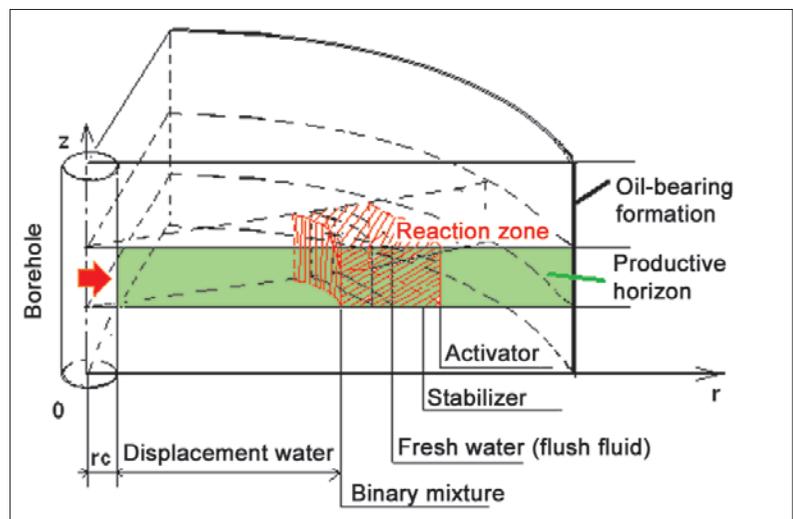


Fig. 3. Diagram of the computational domain in the well bore zone with sequential supply of reagents and formation of the reaction zone

Under these conditions, the distance of the reaction zone from the wellbore is 2.5 meters.

The next stage of the simulation describes the development process of this reaction, in the form of an increase in pressure and temperature in a narrow region surrounding the well and remote from it at a distance calculated in the previous step. The intensity of the reaction, which determines the levels of arising temperatures and pressures, depends on the injection volumes of the reactants, as well as the concentration of salts in their composition.

Studies have shown that when using solutions with a salt concentration of about 10%, the maximum temperature in the reaction zone does not rise above 100°C, and the use of salts with a concentration of about 60% leads to an increase in temperature above 400°C, while pressure jumps due to decomposition of BM and gas emission reaches 800 atm in the reaction zone, the intensity of the wave decreases as it “spreads” from the reaction zone. Fig. 4 shows a graph of the time pressure changes at the well when the “explosive” pressure wave reaches the well. When the reaction distance from the well is 2.5 meters (at 60% concentration of explosives), a pressure pulse of 440 atm comes to the face after about 2.5 hours.

At the third stage of modeling, the process of production from a heated reservoir is calculated, changes in temperature distribution, pressure in the well bottom zone, advance of phase fronts, changes in porosity and permeability are tracked. In the zones of the reservoir,

where the pressure rose above 300 atm changed porosity and permeability caused by the formation of a system of small cracks. The propagation of the thermal front from the zone of interaction of the reacting substances of the TCET showed heating of the formation above 80°C to a depth of 10 meters from the well during the week.

### Conclusions

The TCET methods tested on conventional fields over the past 10 years have shown a good effect in the form of a continuous increase in inflows at fields that are at a late stage of development. Depending on the volume of injected explosives and the concentration of solid explosives in an aqueous solution, it is possible to change the thermodynamic parameters (temperature and pressure) in the reaction zone, due to a change in the overall level of energy release. The use of reaction retarders supplied before or together with an aqueous solution of explosives, allows delaying the development of the reaction for the required period of time necessary for pushing the reaction zone from the wellbore by feeding volumes of squeezing liquids, which makes it possible to carry out the process in a safe mode for the well.

Increasing the concentration of explosives (over 60%) in an aqueous solution makes it possible to obtain temperatures above 400 °C in the reaction zone, which are sufficient to activate the process of generating additional hydrocarbons from kerogen, which indicates the promising application of the TCET method for kerogen-containing fields.

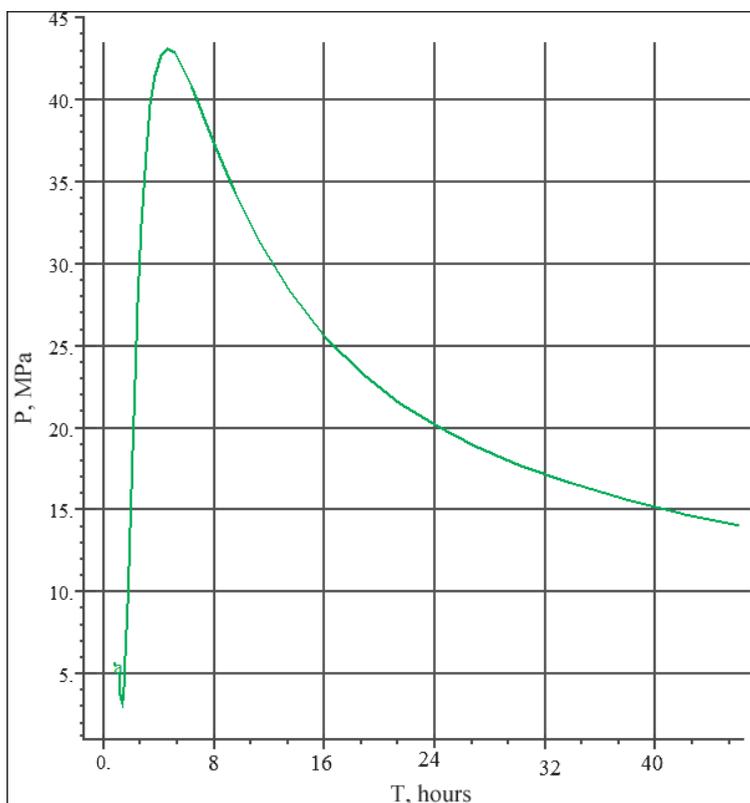


Fig. 4. Dynamics of pressure change at the bottom of the well since the beginning of the BM decomposition reaction

The process of generation of mobile hydrocarbons from kerogen in the model is initiated when the temperature in the reservoir reaches not less than 300°C, however, in the absence of specific field data on the decomposition of kerogen, this process was not considered in the calculation, but the possibility of its generation under various test protocols was evaluated.

As it is known in 2015, the “Shpilman Scientific and Analytical Center for the Rational Use of Subsoil Resources” together with the Ministry of Environment announced the creation of a scientific testing ground “Bazhenovsky “in Surgut region from the Khanty-Mansiysk district (Kuz'min, 2015). The announced list of works concerns laboratory analysis of core material and geophysical research. According to the results of work, the values of porosities (5-30%) and permeabilities (0.001-1 mD) for various sections are already presented.

The research results could be the basis for the creation of adapted mathematical models, based on which it is possible to optimize the development of kerogen-containing formations.

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# Consideration of the processes of oil deposit reformation during long-term operation and deep feeding in modeling the development of oil fields

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**Abstract.** The article is devoted to the study of replenishment of oil reserves in long-developed fields and contains a substantiation of the need for its monitoring and control. This will allow for a new approach to modeling the development and evaluation of residual reserves in the late stages of development of oil fields. In order to identify the conditions for the reformation of the deposits, special geochemical studies should be organized to localize the replenishment sites, as well as geological and commercial studies to determine the rate of oil accumulation in the trunks of highly watered wells. These works will allow selecting the most promising areas of the deposit to search for channels for deep degassing of hydrocarbons and recommending carrying out seismic studies with new innovative technologies for mapping channels and subsequent monitoring of degassing processes. The newly obtained results, combined with the information already available, will allow us to take a new approach to the development of an alternative geological and hydrodynamic model that will determine the rates of reservoir regeneration during development and the volumes of hydrocarbon reservoirs from the depths. It will also help to predict the role of reformation processes in the total oil production.

**Keywords:** oil, degassing, replenishment of reserves, flow of hydrocarbons, reformation of deposits, Romashkino field, long-term development, geochemical studies, oil composition monitoring

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## Introduction

The problem of localization and assessment of residual reserves at the late stage of oil and gas field development is relevant in petroleum geology. In the past two decades, the facts of obtaining light oils from fully developed and water-flooded areas have been repeatedly discussed and published (Gavrilov, 2007, 2008; Goryunov, 2015; Dyachuk, 2015; Dyachuk, Knyazeva, 2016; Kasyanova, 2010; Muslimov et al., 2012; Muslimov et al., 2009, 2013; Plotnikova et al., 2017). At the same time, giant oil fields with a long history of production are of the greatest practical interest, one of the examples of which is the Romashkino oil field.

About 20 years ago in Tatarstan, a group of experts from TatNIPIneft, under the leadership of R.Kh. Muslimov and I.F. Glumov began research on the phenomenon of the replenishment of oil reserves in the deposits of the terrigenous Devonian of the Romashkino

field, aimed at solving problems of great scientific and practical importance for increasing the recoverable oil reserves of developed fields (Muslimov, 2014; Muslimov et al., 2004). The studies were started simultaneously in several directions and included the analysis of geological field information (under the direction of I.F. Glumov, R.R. Ibatullin), geochemical studies (under the guidance of R.P. Gottikh, subsequently with the involvement of specialists from the IOFKh and KFU), geophysical studies of the deep structure and fluid dynamics of the Earth's crust of the Volga-Ural region and adjacent areas (under the guidance of V.A. Trofimov with the involvement of specialists from the VNIIGeofizika, UGGU, IGF UrOR AN, etc.)

## History of studying the process of replenishing oil reserves in Tatarstan

The synthesis of unique information obtained from the study of the basement of the Volga-Ural antecline (VUA), its fracturing and fluid saturation, the compilation and study of geological and field information on the production wells, and the geochemical studies of oil and monitoring of their composition over time suggested

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that there are fast replenishment processes comparable in duration to human life, as well as their widespread in recent times (Kayukova et al., 2012; Muslimov et al., 2004, 2012; Muslimov, 2014 ; Plotnikova et al., 2017; Khisamov et al., 2012).

Modern studies have established that oil fields are associated with oil-bearing faults, which, in turn, appear as oil-supply channels (Trofimov, 2013).

Under the large oil fields there are oil supply channels, due to the activities of which they were formed. During the development of fields, these channels can be activated and replenish the trap with new portions of hydrocarbon fluids. We have shown that the crystalline basement plays a certain role in the constant "feeding" of oil fields of the sedimentary cover with new resources, ensuring the transit of hydrocarbons through hidden cracks and fractures from the depths (Muslimov et al., 1996; Gottikh et al., 2014). The existence of a single source of petroleum generation for oil and natural bitumen (NB) deposits of the South Tatar arch was shown, as well as the formation of fields due to the vertically upward migration of oil and gas fluids through fractures that intersect the crystalline basement and the lower horizons of the sedimentary cover.

Deep regional seismic surveys conducted in Tatarstan and adjacent regions not only provided new information about the structure of the earth's crust and the connection of its structure with the oil-bearing capacity of the sedimentary cover, but also confirmed the existence of a complex system of deep faults under the oil fields (Trofimov, 2013, 2014). Thus a great contribution to the development of the theory of N.A. Kudryavtsev.

### Research results

Studies conducted at the Romashkino field suggest that the detected relics of the hydrocarbon destruction zones indicate the presence of hydrocarbon (HC) filters in these zones, which in a non-uniform thermal gradient field of the basement were successively distilled from the lower zones to the upper ones under the influence of the temperature field and compression phenomena. This is also confirmed by the similarity of the HC of the basement and the cover, by the specific composition of the waters in the zones of destruction and the cover (Plotnikova, 2004).

Degassing processes recorded in the decompacted zones of the basement, and their periodic activation (Plotnikova et al., 2013, Plotnikova, 2004, Gordadze et al., 2005, Gottikh et al., 2004), the connection of the block-fault structure of the South Tatar arch (STA) with the phenomenon of modern migration of hydrocarbons to Romashkino and other fields, geochemical studies of oil and bitumen sedimentary cover, which proved that the carbonate rocks of the Semilukdkisn-Mendymdkskian deposits are not a source of HC inflow in the STA

terrigenous Devonian deposits (Gordadze, 2007; Ostroukhov et al., 2014). All these facts are powerful scientific and practical basis for the creation of a different concept of the formation of oil and gas fields in the VUA, involving a multi-stage impulse flow of hydrocarbon fluid systems into the sedimentary cover under the pressure along the transit fracturing zones.

Bituminological and pyrolytic studies carried out earlier by various researchers have made it possible to establish the wide development of migratory bitumoids in the structural-material complexes of the pre-Paleozoic basement of the STA and adjacent territories. Signs of moving lighter hydrocarbons up the basement section were identified based on a study of crystalline bitumoids from the well 20000-Minnibaevskaya, 20009-Novoeikhovskaya, 23161-Alkeevskaya, etc. (Muslimov et al., 1996; Kayukova et al., 2012; Plotnikova, 2004). The decisive influence of deep-seated hydrocarbon-bearing systems on the formation of oil deposits in a sedimentary cover has been proven based on a study of the trace element composition of oils and organic matter of sedimentary and crystalline rocks (Gottikh et al., 2004).

Analysis of geological field data (GFD) of many years of operation of production wells of the Romashkino field, performed at TatNIPIneft under the guidance of I.F. Glumov, made it possible to substantiate the presence of modern hydrocarbon inflows into the industrial oil reservoir of the Pashian horizon of the Romashkino field (Muslimov et al., 2004) and the existence of localized sections of the inflow of new hydrocarbons. During the analysis of the GFD, a number of criteria were developed, which made it possible to identify in which the HC inflow process was recorded with the highest probability from the total number of production wells. Such wells are called anomalous. Comprehensive analysis of geological field data, performed in TatNIPIneft 2005-2006 under the leadership of S.Uvarov, allowed to select from the entire stock of wells those that met certain criteria of anomaly. Abnormal wells are wells with a cumulative oil production of more than 0.5 million tons, with a production rate of more than 100 tons/day for at least 5 years, with a duration of more than 40 years, with a cumulative oil-water factor of no more than 0.5 m<sup>3</sup>/ton, with increasing flow rates for at least 5 years in the period of declining oil production, i.e. when a long-term natural drop in oil flow rates is replaced by a "sudden" long-term increase in oil flow rates.

Figure 1 shows the dynamics of the ratio of average production rates of abnormal wells to average production rates of normal wells during 40 years of their operation. As can be seen, the maximum values of this parameter were recorded in 1962, 1976 and 1991, that is, at intervals of 14-15 years. Moreover, the effect of differences in flow rates is more noticeable in the initial

years of development, then it fades as the technogenic impacts on the formation intensify and the total use of in-loop injection of water under excessive discharge pressure, but then, against the background of a decrease in water flooding, its intensity again increases (Khisamov et al., 2012). The effect of the flow of light hydrocarbons into terrigenous Devonian strata is confirmed by the dynamics of the density of oil recorded from the results of the analysis of changes in density in piezometric wells, performed by I.N. Plotnikova in 1998-2003 (Plotnikova et al., 2017). Figure 2 shows variations in the number of wells in which a decrease in density was observed.

It is noteworthy that the increase in the number of such wells was noted in 1991 and 1992, which is correlated with an increase in the ratio of average production rates of anomalous wells to average production rates of normal wells in 1991. Some discrepancy is explained by the fact that the density change was taken only from piezometric wells, that is, from a much smaller number of wells than the ratio parameter of flow rates. In addition, the effect of the flow could be, first of all, fixed in abnormal wells, and only then (as the newly received portions of hydrocarbons moved) could affect the characteristics of oil in piezometric wells. Nevertheless, the fact that even in piezometric wells the dynamics of density changes are noted, testifies to the scale of the flow of light hydrocarbons in productive layer – the object of development.

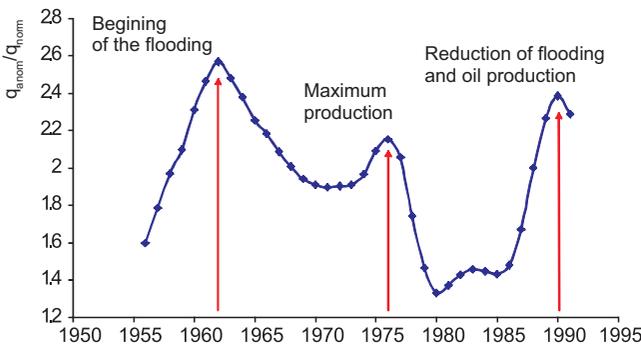


Fig. 1. Dynamics of the ratio of average production rates of anomalous wells to average production rates of normal wells in the Minnibayevsky area over 40 years of their operation (according to Khisamov et al., 2012)

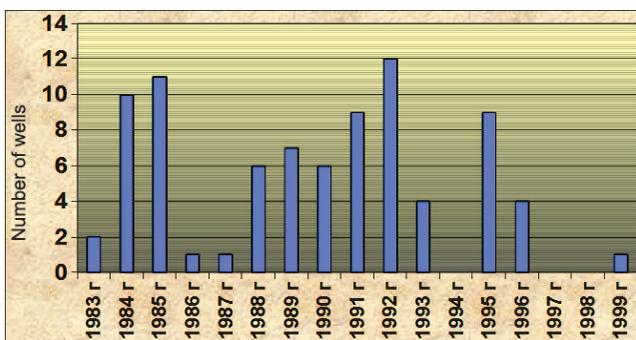


Fig. 2. The number of piezometric wells by years in which a decrease in the oil density from terrigenous Devonian sediments of the Romashkino field was recorded

Synthesis of multivariate studies of identification of wells with anomalous parameters and their relationships with wells with normal parameters made it possible to identify patterns of their location in area and a comparative change over time. The given actual field materials sharply contradict the “law” of falling oil production and are directly related to the established phenomenon – “Recharge”, and therefore require special research and study.

Geochemical studies of oils from abnormal wells clearly indicate their differences in a number of parameters (Fig. 3) obtained from group, elemental, chromatographic, chromatography-mass-spectrometric analyzes and from isotope studies (Kayukova et al., 2012; Plotnikova et al., 2017). The results of these studies allow us to differentiate oil from abnormal wells and normal wells, and also indicate the relationship of the chemical composition of oil with the geodynamic situation of the area. In particular, it is shown (Plotnikova et al., 2017) that oil samples from abnormal wells of the South Tatar and North Tatar arches are characterized by a high content of oils (> 60%) and lowered asphaltenes (<8%), in contrast to the oils of the Melekess depression, where signs of modern hydrocarbon inflow into deposits are not recorded (43% and 15%, respectively). For the samples under consideration, the relative distributions of n-alkanes also differ, which also show a higher

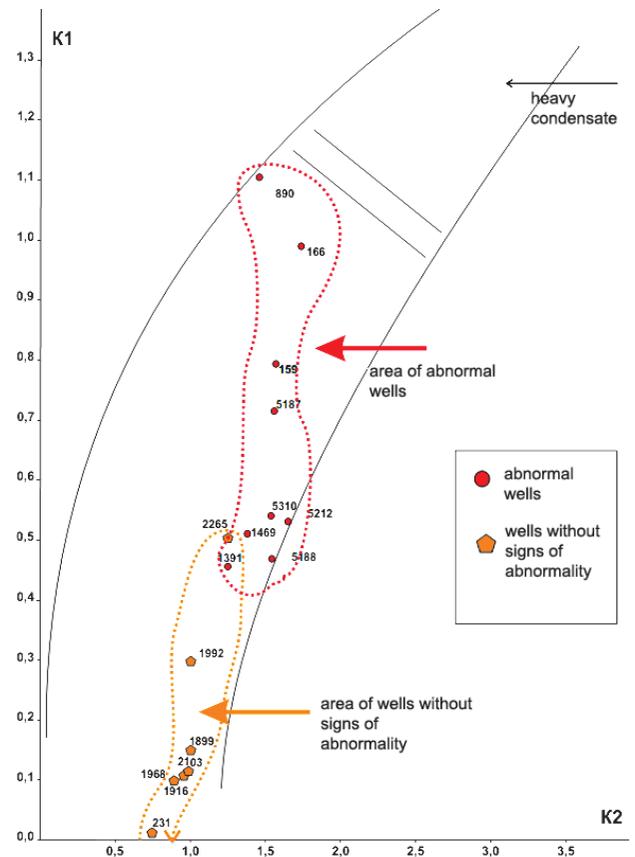


Fig. 3. Differentiation of oil samples from abnormal wells and wells without signs of abnormality by coefficients K1, K2 (Plotnikova et al., 2017)

content of light hydrocarbons in the North Tatar and South Tatar arches and the influence of the processes of biodegradation and oxidation in the oils of the Melekess depression. It is noteworthy that within the Minnibayevsky area of the Romashkino field of the STA, the previously identified various geodynamic activity of the deposits, associated with the differentiated activity of the block structure of the basement, determines the continuous intermittent flow of light hydrocarbons, which is confirmed by the results of geochemical and other studies (Kayukova et al., 2012; Plotnikova et al., 2017; Salakhidinova et al., 2013). Figure 4 shows the location of anomalous wells (prior to the start of flooding and the use of enhanced recovery methods) to the boundaries of the microblocks (Plotnikova et al., 2011), which were selected based on the analysis of the hypsometric position of the “average limestone” reference frame.

### The scientific and practical significance of the results

The results obtained are of great practical importance, since they allow us to quickly carry out areal geochemical studies of produced oils. Application of the developed criteria will allow localizing areas of deposits in whose oils there are traces of newly received portions of light hydrocarbons. Over such areas, in the long term, special

control should be established, since it is on them that reserves can be replenished, periodic increase in well flow rates, and recovery of oil accumulations in the washed zones.

At the later stages of field development, such geochemical studies are necessary, since they allow to identify those areas of deposits where the well operation can continue for a long time.

All of the above allows us to conclude that there is a fact of migration of hydrocarbons through the basement into the sedimentary cover by fracturing zones associated with multiple faults. Thus, it is possible to speak with full confidence about the “HC-breathing” and “feeding” of the lower horizons of the Romashkino field, caused by the degassing of the deeper layers of the Earth.

The analysis carried out allows for a new view of oil fields as a constantly evolving object fed by hydrocarbons from the depths of the subsoil.

The confinement of oil migration routes to fracture zones, the young age of oil deposits, as well as the structure fullness of less than 100% suggest that the oil formation process will continue and, therefore, there will be a modern oil migration and replenishment of the resources under development. The possibility of this process can be argued from various points of view. However, the approach to this problem from the point of view of the inorganic origin of oil is the most realistic

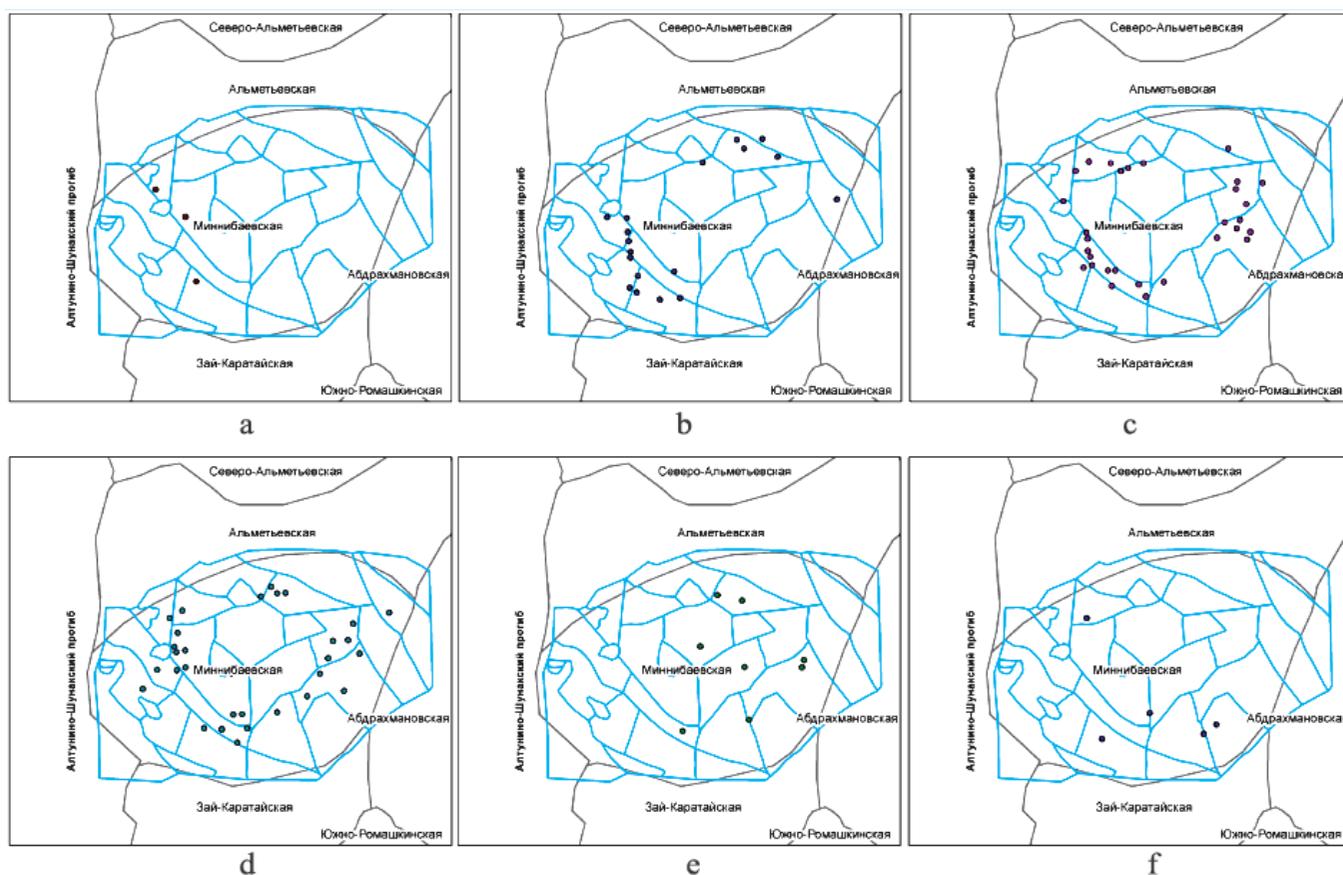


Fig. 4. Connection of the block structure of the basement and sedimentary strata with the placement of wells with different anomalous criteria: a – 1957, b – 1958, c – 1959, d – 1960, e – 1961, f – 1962

and theoretically determined, since the process of the deep generation of hydrocarbons and their periodic entry into the upper horizons of the Earth's crust and sedimentary cover is natural phenomenon controlled by certain geotectonic conditions.

Building models must begin with small fields (deposits) or areas of large fields for which previously approved reserves have been practically or already selected, or these reserves are close to depletion (more than 95% of the initial reserves have been selected). Then, an analysis of the parameters adopted in the calculation of the parameters (porosity, power, oil saturation, etc.) is necessary. Then oil recovery factor has to be analyzed in more detail (maximum possible and achieved displacement factors (according to laboratory and field data), waterflood coverage rates (by thickness and extent), possible man-made changes in deposits during their operation using waterflooding methods. Next, wells are to be selected with abnormal for this reservoir oil production rates and oil production is to be predicted for them and other wells. At present, methodological approaches have been developed (Plotnikova et al., 2017) to extract the anomalous wells and zones of hydrocarbon inflow based on a complex of geochemical studies of oil and gases dissolved in them. Localization of such wells and zones can be carried out based on the study of oil from production wells. Also using the geochemical characteristics of oil from abnormal wells (Plotnikova et al., 2017) it is advisable to monitor the process of the flow of hydrocarbons to determine the frequency and extent of the flow of light hydrocarbons into the reservoir.

Purposefully such geochemical studies in the oil fields of Tatarstan have not yet been studied, but they will allow to study the effect of deep degassing on the formation and re-formation of oil deposits, as well as on the replenishment of oil reserves in the process of long-term field development. At the same time, it is necessary to predict and model the processes of regeneration and re-formation of deposits in the fourth stage of development (Dyachuk, 2015; Dyachuk, Knyazeva, 2016).

After exhaustion of opportunities for increasing oil recovery factor in areas with high oil recovery and limiting watering, experimental work should be carried out to disconnect them from operation, but for a period of time (0.5-1 year or more) to reshape the deposit. The experience of the re-commissioning of previously withdrawn from development sites in the Republic of Tatarstan and other regions of Russia shows that as a result of the re-formation of a deposit, there is a significant (10-15% or more) reduction in water cut and, accordingly, an increase in oil production. Repeated operation of sites in such cases is carried out profitably. After carrying out the experiments, it will be possible

to determine the duration of periods of stopping areas in different geological conditions and recommend a more powerful method of operation of deposits at a late stage with periodic shutdown of production of individual sections for re-formation at simultaneous exploitation of the rest of the highly watered part of the deposit in a special mode. Our estimate indicates a possible additional increase in oil recovery factor by 5 percentage points.

According to the hypothesis put forward by the mechanism of oil reservoir regeneration, the residual oil, migrating through the pore channels under the action of a pressure gradient, which is caused by the difference in the specific weight of the displacing agent and the residual oil, will accumulate at the top of the productive layer and flow into the area where the internal energy for it will be minimal under given thermodynamic conditions (Dyachuk, 2015). Conducted in the monitoring mode from 1998 to 2002 at the Pamyatno-Sasovsky field (Lower Volga) by the efforts of LUKOIL-VolgogradNIPImorneft LLC, detailed studies of the process of hydrocarbon inflow into the deposit clearly showed the need to study the spatial and temporal patterns of its fluid regime (Kasyanova, 2010). Our assessment of the role of "recharge" in the Romashkino field is shown in Fig. 5.

## Conclusion

Considering that the modern vertical migration of fluid flows from the bottom up has geodynamic nature and it is characterized by selective localization both in terms of area and time, 4D analysis of geological, geodynamic and geochemical data in the monitoring mode is necessary to study the flow process (Kasyanova, 2010). Today, the practical possibility and necessity of organizing such monitoring studies in any developed oil field is obvious. In order to identify the conditions for re-formation of deposits, it is necessary to organize special field studies to determine the rate of accumulation of oil in the wells of highly watered wells and transfer wells to a selection not exceeding the inflow rate (candidates are wells in the micro-anticlines of the roof of the reservoir).

The work carried out will allow to choose the most promising areas of the reservoir to search for channels of "feeding" with hydrocarbons from the depths of the subsoil. In these areas, we can recommend seismic studies on new technologies (seismic sides-canner, SLOE, CDP 3-D, 4-D, etc.), monitoring of geological field data, geochemical characteristics of oil and dissolved gas, as well as geodynamic parameters of the deposit, field and the surrounding area.

The collection of accumulated data will allow creating a model, on which it will be possible to carry out calculations, determine the rates of regeneration of

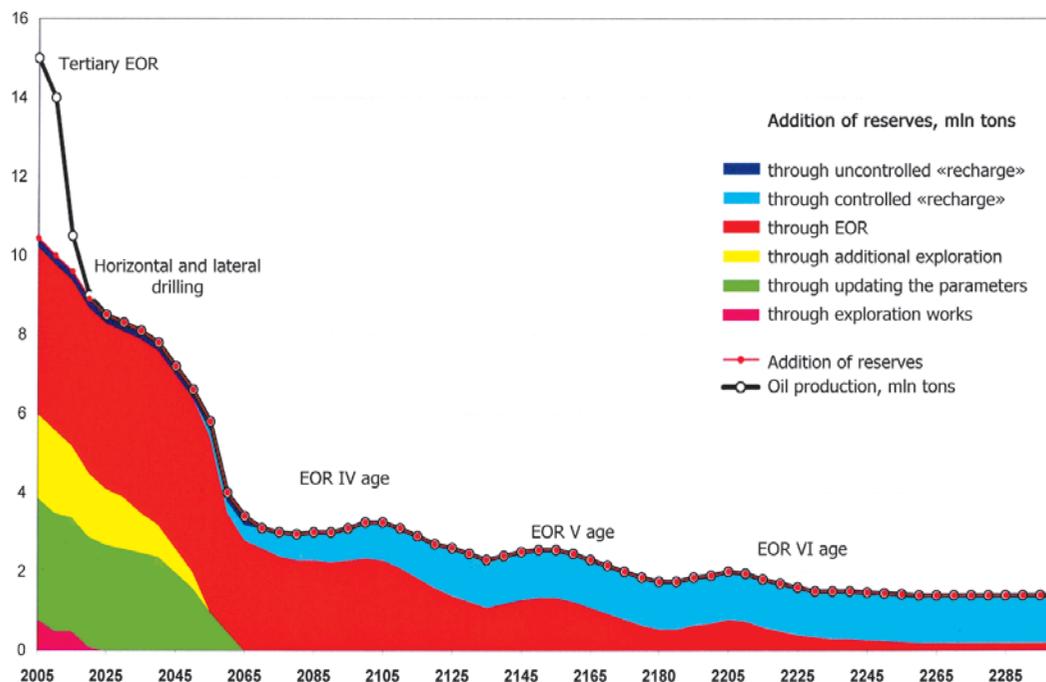


Fig. 5. Dynamics of oil production and reproduction of oil reserves in the Romashkino field since 2005

deposits in the development process and the volume of “feeding” of deposits with hydrocarbons from the depths and predict the role of processes of re-formation of deposits in total oil production.

Starting to model these processes is necessary today.

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# International experience of E&P software solutions development

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**Abstract.** The international market is full of high-quality solutions for reservoir modeling provided by specialized service and consultancy companies. Nevertheless, oil and gas operators independently develop their own home-made software solutions, although, at first glance, it is much easier for them to buy ready-made package solutions. What is the purpose of spending time and money on this activity? What do companies need today to successfully create and commercialize software products?

An example of the development of a software package based on own solution in the Skolkovo start-up system is given.

**Keywords:** reservoir modeling, in-house software solutions, IT-technologies, start-up Skolkovo

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## 1. Introduction. Geoscience and modeling, tasks and solutions

Geoscience is a scientific method for studying the planet Earth and its geological systems and natural resources in the past, present and future. For the purpose of developing hydrocarbon resources, the methods of various Earth sciences are applied: geology, geophysics, geochemistry, petrophysics, geomechanics.

Based on data collected from different-scale sources, specialists in geology, geophysics and engineers study the processes occurring in oil and gas systems and reservoirs (Fig. 1).

If we make a small excursion into the history of the development of computer simulation methods in our country, we will see that these methods appeared and are developing very quickly, in the time scale of one human life. Until the 50s of the 20th century, wells were drilled along the structural grid, then with the development of seismic prospecting, decisions were made on structural maps. A qualitative leap in the study of oil and gas systems occurred in the early 80s, when the software for computer modeling began to actively develop.

During the life cycle of a field, a large amount of diverse and varied data with a high level of uncertainty is continuously recorded (Fig. 2). For example, seismic information, on the basis of which the interwell space is modeled, has limitations related to the resolution of the signal recording. All these data must be processed and taken into account for the construction and monitoring of the model.

## 2. The experience of Western oil companies in the development of in-house software – own modeling software

Two major groups of companies specializing in the development and sale of software products compete on the international market:

- oil service “giants”, such as Schlumberger, Halliburton, CGGVeritas, Emerson Electric. For them, the development and creation of software is not the main business, for example, Schlumberger’s revenue from software sales does not exceed 1-2% of total revenue;

- companies for which the development and sales of software – the main business: Kappa Engineering, RFD, TGToil and others. Figure 3 shows a graph of growth in the global market for software for oil production (Analytical Report on Oil Production Technologies, 2018).

But there is another type of software – operator companies, holdings that profit primarily from oil production. They also allocate considerable resources for creating their own software products.

So why are Western oil holdings developing their own software if the market is filled with high-quality solutions? Companies have super profits, and, at first glance, it is much easier to buy ready-made package solutions.

Let us consider a few examples of the successful creation of home-made software:

- Concern Total has a large research center in the south of France in the city of Pau. It develops software in the field of seismic image processing of sub-basement complexes (Sismage) and modeling of gOfrac fracture reservoirs. Total, along with Chevron, it is part of a consortium to develop an Intersect simulator, supplied by Schlumberger.

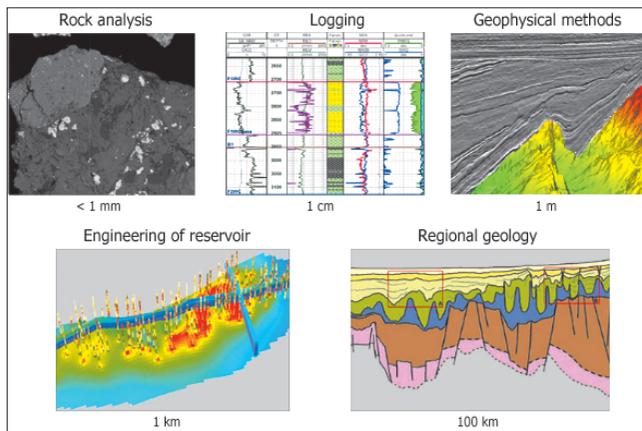


Fig. 1. Diversity of input data

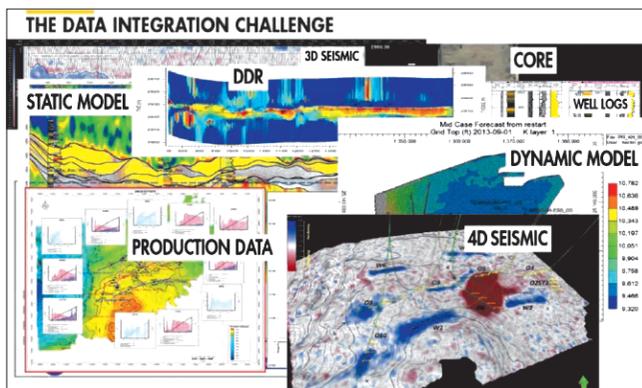


Fig. 2. Integration of modeling stages

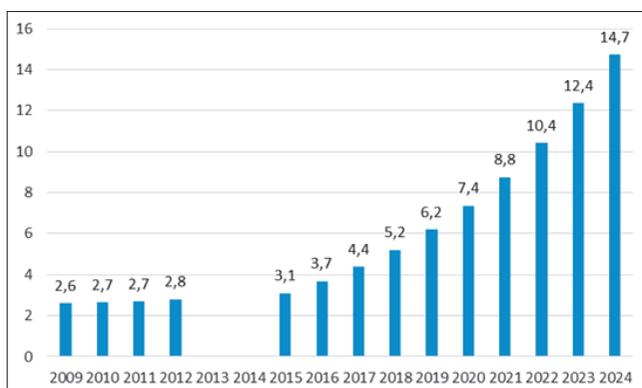


Fig. 3. Dynamics of the global market for software for oil production (in US dollars). Skoltech Assessment (Analytical Report on Oil Production Technologies, 2018)

- Shell has its own research center in the Reichveyk where the MoReS simulator was developed. Openworks drilling applications are developed in collaboration with Halliburton (Innovation through research and development. <https://www.shell.com/energy-and-innovation/>).

- BP-Amoco – in the past, the developer of the Falcon simulator, now the ownership of the product with the commercial name Nexus has been transferred to Halliburton.

Analysis conducted on the basis of available information and several interviews with specialists of these companies showed that no company sells its products on its own.

The objectives of creating their own developments by Western operators are as follows:

- to maintain the image of a high-tech company,
- for the formation of highly professional competencies of its specialists for analysis and testing for other vendors,
- to create their own solutions that are not dependent on plans for the development of new products by major vendors,
- in the case when the cost of acquiring and maintaining licenses is comparable to the content of its own staff of programmers.

The programs are used internally, and products are transferred to vendors for commercialization on the foreign market, since oil companies do not have their own marketing and software structure.

The peculiarity of the American market is that there are a huge number of tens of thousands of small companies creating software and competing with each other. The role of oil and gas holdings – support for startups and small companies, despite the fact that only one of the 10 companies really “shoots”.

### 3. Experience in the development of in-house software by Russian oil companies

The first SCS-3 complex for processing and interpreting geophysical data, which all the country's trusts were equipped with, was created back in the 70s in the CGE. Currently, there are a number of software systems created by people from the CGE (Geoplat, Prime) and other independent developers.

Russian holdings are also actively developing software to ensure less dependence on Western suppliers (Rosneft, Gazpromneft, Tatneft, Surgutneftgas). However, 90% of the purchases of software are still carried out by traditional vendors, while only RFD has entered the wide international market from Russian suppliers.

### 4. What a startup needs today to successfully create and commercialize software products?

- It has to have the development demanded by the market;

- Go to the niches and be the best in them;
- Have advantages in speed of calculations and convenience interface. 10-15 years ago, the most successful creators of software were the algorithmic specialists; now the world is moving towards the quality of visualization and the simplification of human-computer communication;
- Have a strict motivation, which is possible only if you have a common goal and receive a salary in a startup. Not your business – motivation is falling;
- Have about 10 people with different specializations

per engineer in a team: technologist, programmers, tester, support specialist, instructor, lecturer, marketing specialist, salesperson;

- Create in conditions of free competition, fight for grants. If there is only state regulation or state order, the market will be destroyed.

With the oversupply of traditional offers on the market, the future lies in universal commercial platforms to which it will be possible to attach the necessary modules to solve any tasks.

### 5. An example of the development of a software complex based on its own solution, focused on the implementation of an algorithmized production problems in the start-up Skolkovo system

*Project name: Development of a software and methodological complex to improve the management methods for the development of oil fields.*

The choice of topic was based on the successful history of cooperation between TATNEFT PJSC and KAPPA Engineering, as well as the importance of the task – with the help of Government support (Skolkovo Foundation) by start-up companies to ensure the solution of important tasks for the government to improve the efficiency of oil field development management.

Project Development Plan for 2016-2018:

- obtaining the Skolkovo Foundation resident status,
- creating a startup after obtaining resident status,
- conducting parallel studies with the aim of creating a methodology at the end of 2016 and software technology at the end of 2018.

- submission of documents for the grant.

*Start the project.* At the beginning of 2016, work began on creating a methodology for optimizing the operating modes of wells and at the same time creating an application for obtaining the Skolkovo resident status on the topic “developing a software and methodological complex to improve the management methods for developing oil fields”.

In December 2017, the application was accepted by experts with a score of 28 out of 30 possible points. At present, the resident company Skolkovo ETA Engineering has been established.

The plan for the subsequent development of the project in the Skolkovo IT cluster:

- Technical development. Designing an automated data collection system at the field within the framework of the concept of an intellectual field, creating plug-ins, developing a batch module, or integrating with already existing solutions.

- Commercialization. Market research, marketing: participation in international conferences, seminars, publications in specialized journals, promotion of technology in the foreign press, implementation of

pilot projects. Development of technical and customer support systems.

- Carrying out optimization calculations, improving algorithms, searching for ideas and projects to expand the range of innovative solutions to optimization problems (drilling, geophysics).

Development prospects. Work on the creation of a portfolio of R&D projects and a flexible system of external start-up projects are advantageous for the company, since it will allow to receive tax benefits, grant financing (not only from Skolkovo), to attract external Russian and international experts for specific tasks for the duration of the project.

### 6. Conclusion. Generation-Z is the future

The stages of development in the whole IT industry can be represented in the form of three platforms. We are now at the level of the 2nd platform, based on traditional personal computers, the Internet, client-server architecture and hundreds of thousands of applications (The 3rd Platform is Evolving <https://www.idc.com/promo/thirdplatform>).

The concept of the Third Platform is based on four elements: big data, mobile devices, cloud services and social technologies. Applications, content and services built on the basis of the Third Platform technologies will be available to billions of users (Review and assessment of the prospects for the development of the global and Russian IT markets, 2015).

New IT technologies (neural networks, artificial intelligence, machine learning, cloud technologies, Big data) will develop very quickly, followed by application programs (Fig. 4). It is possible that, under the influence of the development of IT industry tools, the generation-Z



Fig. 4. Three platforms in the e-fusion of the IT market. According to IDC, 2014

will create new algorithms and software that will give a new qualitative leap in the development of oil and gas IT technologies.

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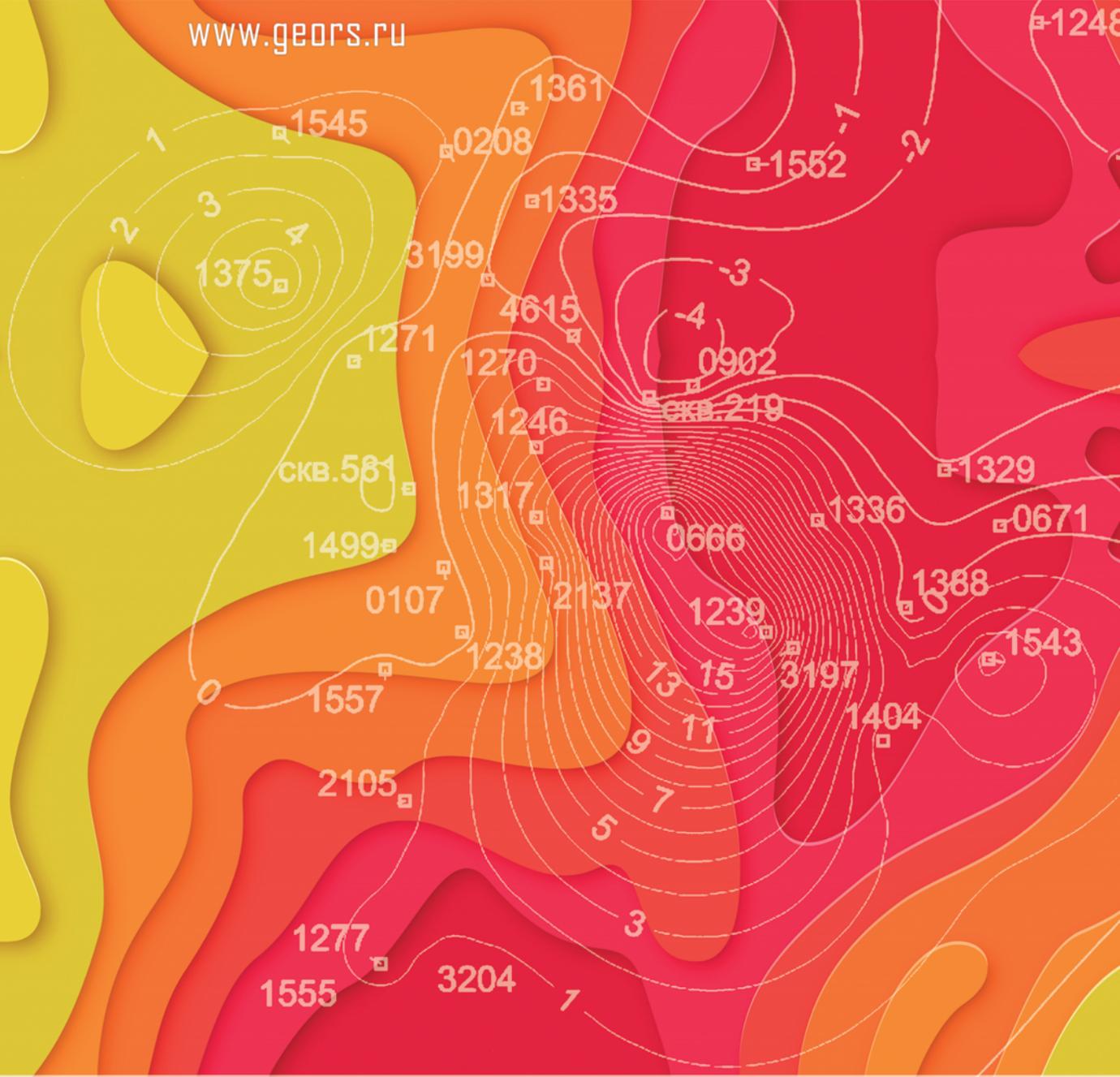


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# The main problems of developing deposits of unconventional hydrocarbons in ultra-low-permeable and shale sediments

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**Abstract.** The shale revolution and the great progress in the US in the development of deposits in tight, ultra-low-permeable, shale strata put the issues of studying and developing unconventional deposits on the agenda. The special geological structure of the deposits of unconventional oils makes it necessary to use new (different from traditional) methods of prospecting, exploration and development of such deposits. And this, in turn, requires a new approach to studying the features of the geological structure and the creation of geological and hydrodynamic models, taking into account the fracturing fields and heterogeneity in the distribution of the reservoir's oil content and the productivity of producing wells. The article deals with the problems of studying the fracturing of rocks and the need to take it into account in the geological and hydrodynamic modeling of oil and gas deposits. The obligatory use of innovative seismic technologies in studying the geological structure of fields and new technologies for studying sludge during drilling is the key to a successful study of unconventional reservoirs and shale strata at various stages of geological exploration and development of oil fields.

**Keywords:** deposits with hard-to-recover oil reserves, unconventional oil deposits, low permeable, tight, ultra-low-permeable layers, deposits of super viscous oils and natural bitumen, oil recovery factor, pilot-industrial works, shale rocks, hydraulic fracturing, geological and geological-hydrodynamic models

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The experience of the United States and other Western countries shows the huge oil and gas potential of tight rocks, the basis of which, they believe, are shale formations. But the latter, based on the experience and accumulation of these types of rocks, are only part of the general concept of tight rocks. Thus, the work (Prishchepa, Averyanova et al., 2014) states: "On the one hand, the concepts of "shale oil" and "gas and oil and gas of tight rocks" can be considered not to coincide, primarily because of the criteria for their separation, and on the other hand, it is necessary to understand that the latter completely absorb the former. The term "oil from tight rocks – low-permeable reservoirs" that most commonly used in the US oil industry today is more used to denote the whole diversity of unconventional sources of oil, for the extraction of which special technologies are needed, including drilling of multi-layer horizontal wells, multi-stage fracturing, microseismic and microscopic observations."

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Table 1 shows the classification of rocks according to the main parameter – permeability, which unequivocally indicates our lag behind the leading global trends. Thus, the interval of standard permeability values from 1.0 to 10 mDa established for fields of the Republic of Tatarstan is hopelessly outdated. The reservoir rocks, the permeability of which is enclosed in this interval, according to the above classification, belong to medium-permeable, and oil reserves in reservoir rocks with a permeability less than 1.0 mD must be taken into account, since they are objects of industrial development using modern production technologies. The categories of tight rocks (from low-permeable to nanopore) should be studied as hydrocarbon-saturated, taking an active part in the processes of in-situ filtration and oil production, and the low-permeable group of rocks is of interest from the standpoint of potential oil production facilities.

Today, leading oil and gas companies with experience in developing both conventional and non-conventional oil and gas production facilities adhere to the classification of hydrocarbon (HC) accumulations in terms of the technological aspect of their development (Fig. 1):

- conventional deposits confined to conventional reservoir rocks and controlled by impermeable beds and traps;

Permeability, D	Rock permeability quality	Reservoir
More than 1,00	Very high permeable	Conventional
From 1,00 to 0,10	Highly-permeable	Conventional
From 0,10 to 0,01	Permeable	Conventional
From 0,010 to 0,001	Mid-permeable	Conventional
From 0,001 to 0,0001	Low-permeable	Unconventional
From 0,0001 to 0,00001	Ultra-low-permeable	Unconventional
Less than 0,00001	Extra-low-permeable	Unconventional
0,000000001	Nano-permeable	Unconventional

Table 1. Characteristics of permeability of reservoir rocks regardless of the type of voids (Prishchepa et al., 2014)

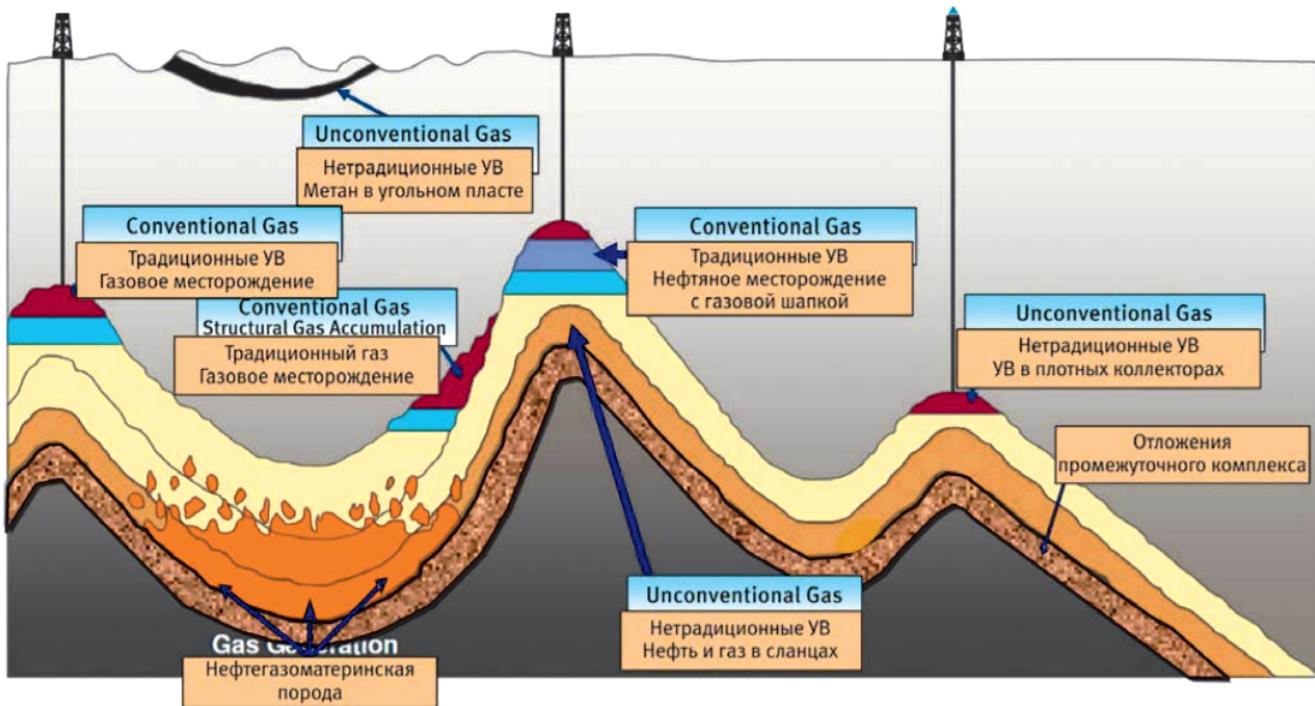


Fig. 1. General ideas about the localization of conventional reservoir rocks and unconventional deposits in tight and source rocks (Shuster, Punanova, 2018)

- unconventional accumulations in high-carbon shale strata not controlled by the structural factor and impermeable beds;

- unconventional accumulations in tight rocks or semi-reservoirs – clayey sandstones, aleurolites, carbonate rocks, which may also not be controlled by the structural factor and impermeable beds (Prishchepa, Averyanova, 2014a).

Important features of oil and gas deposits in shale oil reservoir and tight oil reservoir that distinguish them from conventional deposits are the following:

- continuity, when hydrocarbons are “everywhere and nowhere” in the dispersed state in rocks with low matrix permeability (Morariu et al., 2013; Prishchepa, Averyanova et al., 2014; Prishchepa, Averyanova, 2014b);

- uncontrollability of structural and stratigraphic factors;

- controllability of the lithological factor, as well as fractured fields.

Unconventional reservoir rocks, the oil content in which is controlled mainly by the lithological factor,

can have a very wide area distribution. Consequently, the calculation of reserves in them requires different approaches.

Performed at the Kazan Federal University under the leadership of V.P. Morozov’s analysis of the distribution in the carbonate sediments of the lower and middle Carboniferous of conventional and tight oil-bearing reservoir rocks revealed a certain type of section in the Tournaisian sediments, which can be attributed to unconventional reservoir rocks (Morozov et al., 2016).

This type of section is most fully studied on the eastern side of the Melekessky depression in the Kizelovskian and Cherepetskian sediments of the Upper-Tournaisian subsurface. Probably, such deposits are widespread, as indicated by the absence of conventional carbonate reservoir rocks in the Tournaisian deposits in many fields on the eastern side of the Melekess depression.

Such unconventional accumulations are characterized by low values of reservoir properties and oil saturation. The porosity of such rocks, as a rule, rarely exceeds 5%, the maximum permeability is the first MD, and the oil saturation by mass varies from 5-8%.

Such tight oil-saturated carbonate rocks have significant advantages:

- the estimated large area of distribution (about 5 thousand square kilometers);
- large thickness – up to 30 m;
- estimated large geological resources;
- the presence of mobile oil fluid (according to thermal analysis of rocks).

Based on the work performed, the calculation of geological resources of oil in tight carbonate rocks was carried out. Studies show that the geological resources of oil, concentrated in the Upper-Tournaisian subsurface on the eastern side of the Melekes Depression, are tentatively estimated at 8025 million tons (Morozov et al., 2016).

Oil-gas-containing tight rocks in nature are much more than conventional reservoir rocks, due to the conditions of sedimentation and the subsequent transformation of sediments. This is evidenced by available data on the resources of conventional oils and liquid hydrocarbons of shale deposits. To assess oil reserves in tight and shale rocks, specific types of research are needed, and for their extraction, technologies that are fundamentally different from technologies for recovering hard-to-recover reserves. The increase in permeability and drainage area by creating artificial cracks and filtration channels is common to these technologies. At present, this is done by drilling horizontal wells and complexing them with multi-stage hydraulic fracturing (HF). This technology is no different from technology for conventional tight rocks and shale deposits. The latter differ from the former only in terms of sedimentation. One definition of shale is as follows (Downey et al., 2011): “Oil shale – fine-grained sedimentary rocks containing minerals and a large amount of kerogen, which, in turn, is valuable as a raw material for subsequent processing into shale oil”.

The first three parameters are usually considered: fracturing, porosity and permeability, which play a major role in the accumulation of hydrocarbons in oil shale and the ability to extract these hydrocarbons from productive strata.

The formation of cracks in rocks during the transformation of organic material into kerogen can occur in two directions: in rocks rich in organic material, due to dehydration with the formation of small cracks with low permeability (subsequently, as a result of tectonic influences, secondary cracks are formed in the rocks); in rocks containing smaller volumes of organic material (cracking occurs on a smaller scale than in the first case). In general, the width of the cracks is extremely small (less than 0.05 mm), but its length can be thousands of times more than the width. Cracks in oil shales represent a small volume and cannot play a significant role as storage of basic organic material.

In the structure of the pore space in the productive

strata of shale oil deposits, three main components can be distinguished: the porosity of the rock matrix; porosity formed by micro- and macro-fracture; porosity of syngenetic organic matter dispersed in the rock. The first two types of porosity do not play a noticeable role in the mechanism of conservation of shale oil resources. The porosity of the kerogen, as well as the space between it and the grains of the rock matrix can be in the range of 2.4-2.7%. But when samples of such shale are heated, its porosity can dramatically increase to 25-50% (depending on the amount of organic matter (OM) contained in it).

This heterogeneity leads to the fact that in a large area of development of shale and similar deposits there are no oil flows from the drilled wells, or they are non-industrial. However, in some areas drilled wells receive abnormally high flow rates. In the US, such sites are called “sweet spots”. This is typical of Bazhenov deposits in Western Siberia and, to a lesser extent, in the Domanic deposits of the Volga-Ural oil field.

On the territory of Tatarstan, the prospects for the development of oil shale fields may be associated primarily with the rocks of the Upper Devonian domanicoid formation, with the Semilukskian (Domanic) horizon, as well as with the Rethitskian (Mendymian) horizon and domanicoid formations of the central and onboard zones of the Kama-Kinel deflection system (Fig. 2).

First of all, it should be noted that, in fact, deposits of shale oil and gas, as well as the oil-bearing capacity of Domanicites and Bazhenites, have not continuous distribution (carpet), as was previously supposed and still seems to many researchers, but are localized in certain areas.

In the analytical review of S.M. Akselrod (Akselrod, 2011, 2013) it was noted that according to the logging of productivity, performed in a large number of horizontal wells, the actual productivity of the well correlates poorly with the length of the horizontal wellbore, which is probably due to lateral heterogeneity of shale. This is also the reason for the uneven distribution of inflow over the length of the trunk: in many wells 90% of the total inflow accounts for one third of the perforated intervals.

As the analysis of the selection dynamics has shown, 12-18 months after the well has been commissioned, its production rate drops to 20-40% of the initial one and then continues to decline. Therefore, to maintain the required level of production from the field, it is necessary to drill a large number of wells. This is a very important point, indicating that in tight low-permeable reservoirs of shale fields, oil does not migrate laterally, is not “pulled” to the well when developed due to the small radius of drainage. The productivity and oil-bearing capacity of shale fields is highly heterogeneous, and their development itself is a gradual and phased development

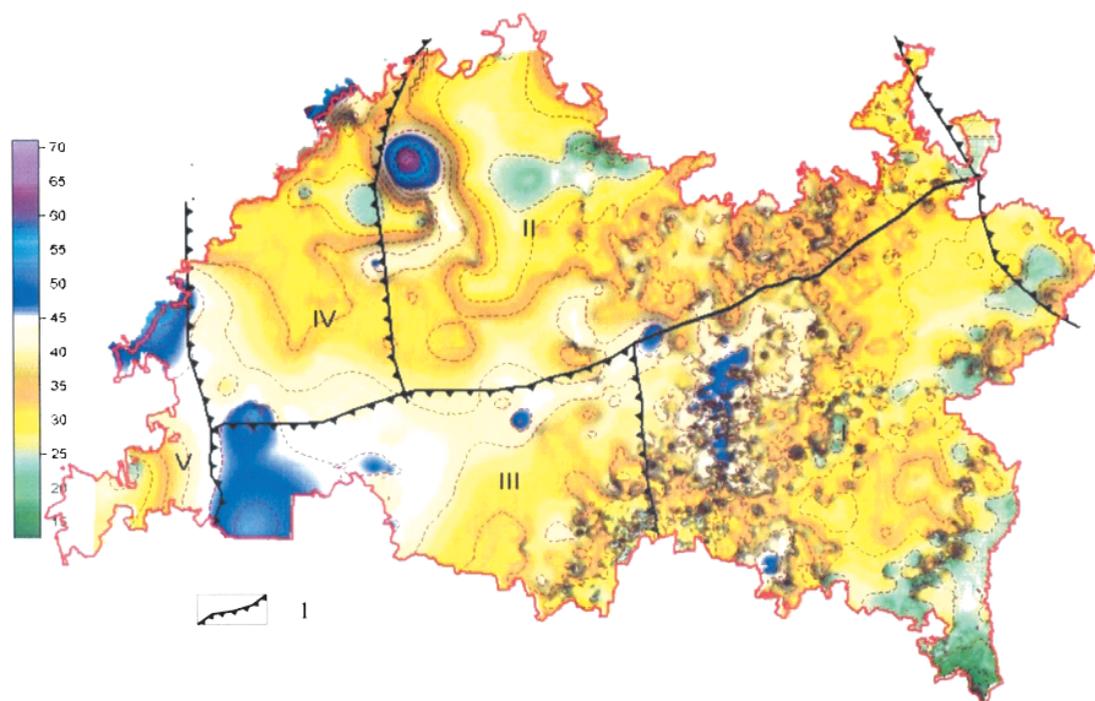


Fig. 2. Capacity map of the Semilukskian horizon of Tatarstan (according to Khisamov et al., 2010). I – modern boundaries of the structures of the 1st order; I – South-Tatar arch, II – North-Tatar arch, III – Melekess depression, IV – Kazan-Kazhim aulacogen, V – East slope of the Tokmov arch.

of separate (apparently hydrodynamically unrelated) sections of the sequence, the formation of which is most likely due to local foci of fracturing.

Consequently, the study of the development of fractured fields in areas is one of the methods for searching promising areas within which local oil deposits can form not only in the Sargayevskian-Rechitskian complex of rocks, but also in the overlying sediments of the carbonate Devonian.

Thus, the primary task is the search and detailed exploration of areas confined to fractured zones. And the increased fracturing is controlled by deep faults of the sedimentary sequence, going into the basement. In zones of fracturing, well flow rates depend on the material filling these cracks (these are small or coarse-grained siltstone, or even grains of sand fractions) (Lukin, 2011).

Modeling for the purposes of prospecting and exploration consists in estimating the forecast resources in large areas of development of promising objects. Here the following data appears: thickness, porosity, organic content, its maturity, silica content and tight limestone, geological and geochemical features of shale strata are studied. Such models are sufficient to search for promising areas.

Exploration work on models should be carried out taking into account the peculiarities of the geological structure of tight rocks and shale formations. In most cases, the usual methods associated with the search for elevations do not work here. Shale deposits, tight rocks often form fields, overlapping with underlying deposits. However, the areas of interest for the search

for hydrocarbons do not have a continuous development due to the large zonal heterogeneity.

Special searches are needed to search for sites of interest. Here, such methods as seismic side-scanner, seismic location of emitting sources, low-frequency seismic prospecting can be used. The best results are obtained by combining methods for studying areal variations of the gamma-field, gravity prospecting and modern methods for interpreting 3D seismic data. Such studies will localize the most promising productive areas. There is also a large role of geochemical and laboratory studies of rocks and fluids and dispersed organic matter that saturate them.

The lack of genetic relationship between syngenetic organic matter of domanicites and oil of Pashian, Kynovskian horizons (Plotnikova et al., 2013), as well as the presence of domanic migration of bitumen, similar in composition of oil terrigenous Devonian, said the formation of deposits of oil in Semiluki, mendymskom and overlying horizons in fractured reservoirs due to the upward vertical migration from below (Ostroukhov et al., 2014, 2017; Plotnikova et al., 2013, 2017).

The study of areas outside the structural uplifts is one of the most important areas in the search for unconventional oil deposits in the domanicites; it is necessary to study the entire territory of the license area, including areas outside the structural uplifts and contours of existing deposits in traditional reservoirs.

An analysis of the distribution of deposits in shale reservoirs of the Sargayevskian-Rechitskian complex showed that it does not obey the structural factor. Thus,

the object of the search for deposits in unconventional reservoirs should be the entire area of the license area, including the marginal areas of uplifts and the space between them.

The use of high-precision gravity survey made it possible to visually verify that the mineralogical density of ordinary limestones and rocks of the Domanic facies, enriched with organic matter and silica, is significantly different. The increase in the share of organic matter in the rock naturally leads to a decrease in its density to 2.3 g/cm<sup>3</sup> and less. Thus, the areas where Domanicites dominate the Semilukskian horizon can be identified with the help of high-precision gravity prospecting. In addition, it is established:

- all the fields and deposits of hydrocarbons in the gravitational field correspond to characteristic local negative anomalies;

- the contours of local anomalies correspond to the contours of hydrocarbon deposits, and in the case of a multilayer deposit – to the external contour of deposits;

- the magnitude of the amplitude of local anomalies serves as an indicator of projected hydrocarbon reserves.

In addition to the above, considerable resources in tight, ultra-low-permeable reservoirs are available at existing fields. Such rocks have so far almost not been studied.

In order to study promising ultra-low-permeability rocks in existing and new oil fields, downhole methods for determining fracturing are needed (today they are available in practice).

*The study of fracturing according to the logging and the results of drilling wells.* At the end of the last century under the leadership of R.P. Gottikh (Gottikh et al., 2004; Gottikh et al., 2006; Gottikh et al., 2007) a method was developed for mapping areas of heightened fracturing of the geomeia based on the analysis of areal gamma field variations in the Semilukskian horizon and in other later sediments.

The confinement of the majority of fields to the centers of increased permeability of rocks poses the problem of identifying fractured zones as one of the most important in exploration. First of all, they are solved in Tatarstan with the use of seismic materials.

The decisive role of inherited fracturing in the migration of fluids, the association of hydrocarbon accumulations to their development areas, the possibility of registering permeable zones based on the anomalous values of areal gamma-field variations suggest recommending the use of radioactivity in rocks as an unconventional method to search for missed deposits in exploited fields, especially in complex reservoirs that are the carbonate rocks of the Upper Devonian and Lower Carboniferous.

*The study of fracturing geosystems by seismic data.* Currently, new fracture field mapping technologies have

been successfully applied at existing fields. In particular, the processing of 3D seismic survey materials makes it possible to obtain cubes of fracturing and oil saturation development using different types of waves. According to the results of 3D seismic survey data processing in Texas (shale), Iran, Orenburg region, Western Siberia, very interesting results were obtained – well production rates are determined by fracturing fields, oil inflow zones in the reservoir and fluid flow directions in the reservoir (Kuznetsov et al., 2016; Kuznetsov et al., 2017). Uniform placement of the project production wells without taking into account the development of fracture fields and fluid flows leads to the drilling of low producing wells, while the main production is achieved due to a small percentage of high-production wells.

To increase the field and geological efficiency of seismic prospecting, especially for hydrocarbon deposits in low-permeable and shale strata, it is proposed to apply a new seismic research methodology based on the integrated use of waves of different classes: specularly reflected, diffusely reflected and microseismic emission, which have a dominant dependence on different geological parameters : structures, fluid saturation and fracturing of the geological environment, respectively (Kuznetsov et al., 2016; Kuznetsov et al., 2017). These waves make it possible to obtain independent information about the structural form of the trap, heterogeneity (oil, gas or water?) and non-uniformity of its fluid saturation and spatial distribution of open fracturing in the geological environment, including low-permeability and shale hydrocarbon-rich strata. A comprehensive analysis of this information allows us to select the optimal locations and directions of drilling of vertical and horizontal trunks, respectively, to ensure the maximum possible inflow of hydrocarbons. The implementation of this methodology is carried out on the basis of a complex of seismic studies, including the standard CDP technology and the innovative technologies “Seismic side-view locator” and “Seismic location of emission foci”, created in 1990 and 2005, respectively, by scientists and Specialists of the Scientific School of Oil and Gas Seismic Acoustics of prof. Kuznetsov O.L. to study fracturing, fluid saturation type (“oil-gas-water”) and other characteristics of the geological environment. The results of research on these technologies are confirmed by dozens of wells in oil and gas fields in various regions of Russia and abroad: Iran, Brazil, USA, Vietnam, etc.

*Gas logging and the study of shale slurry.* One of the most effective ways to obtain information about the structure and fluid saturation of shale strata can be improved and modified gas logging, equipped with modern analytical tools. The most detailed this issue is considered in the works of S.M. Akselrod (Akselrod, 2011, 2013). In particular, in its scientific

review, devoted to the problem of development of shale formations, new technologies of gas logging and on-line analysis of sludge in the process of drilling are considered in detail. The author of the review notes that such important characteristics of shale as relative fragility (brittleness), as well as thermal maturity of kerogen, according to logging data, are not defined in principle. And other significant parameters, such as mineralogical composition, organic matter content, mobile and stationary oil, permeability necessary for the assessment of reserves and productivity, according to logging, are estimated with a certain degree of uncertainty. Therefore, when drilling wells, an important and necessary component of identifying and studying oil deposits in shale and low-permeable carbon-containing carbonate strata are gas logging and research of cuttings, which are produced directly in the drilling process, both at the well and quickly in the laboratory.

Currently, such technologies for studying sludge in the study of shale are developed by Weatherford International Ltd and are already being successfully used in practice. The technology includes the determination of TOC (total organic carbon), thermal maturity of kerogen, the assessment of the presence of residual oil and the conduct of distillation by means of mobile equipment. One of the principal elements of this technology is advanced gas logging, which uses semi-permeable membranes that are placed directly into the jet of washing fluid, which allows us to capture gaseous hydrocarbons immediately from the mud, and not from the air. The analysis is made for 50-60 s.

Sludge analysis is performed directly on the well with a set of special mobile equipment. This equipment allows us to:

- Carry out the extraction of sludge, which allows to evaluate the content of hydrocarbons C1-C8, benzene and toluene, as well as gases CO<sub>2</sub> and N<sub>2</sub>;

- Evaluate the mineral composition of rocks using X-ray fluorescence (XRF) and X-ray diffraction scattering (XRD) instruments, which can be obtained within 45-60 minutes after taking sludge from a vibrating sieve with an accuracy not inferior to laboratory research using the same method. In the course of such an assessment, the content of quartz, opal, plagioclase, and potassium feldspar is determined. The total clay content, the presence of carbonates, pyrite, anhydrite, barite and other minerals are also determined. It is assumed that these studies can replace lithological logging on the cable.

- Assess the TOC and fragility of rocks. It should be noted that in recent years, a new generation pyrolyzer HAWK has been successfully used to determine TOC and geochemical characteristics of oil and gas fluids in the rock, which allows it to promptly obtain comprehensive geochemical information directly at the

well to assess the presence of mobile oil in the reservoir and its industrial accumulation.

- Assess the fragility of the shale according to its ability to crack with minimal external stress, which is necessary to predict the effectiveness of hydraulic fracturing. The fragility index (brittleness index) depends on the mineral composition of rocks and is determined according to XRD and XRF (with proper calibration). And now, experts have already proposed an algorithm for determining the brittleness of shale of both quartz and carbonate composition.

Currently, a new modification of gas logging, carrying out the study of additional pyrolytic parameters for the sludge, as well as mineralogical studies and the study of the geomechanical properties of the sludge during drilling, allows to obtain comprehensive information without coring.

The introduction of this technology in Russia and Tatarstan will make it possible to obtain the necessary lithological-geochemical information and assess the prospects of the domanicites already at the drilling stage, without spending large funds on the selection and study of core.

Currently there are a sufficient number of methods for searching and detailed study of fractured zones. Some of them are used on an industrial scale, some are at the stage of pilot works, others at the stage of research and development. These methods are sufficient to address exploration.

However, for the design of modern technology development, especially the application of new innovative methods and methods for enhancing oil extraction, their effectiveness is insufficient. We need their further improvement.

Production methods depend mainly on the geological and physical features of the deposits. Choosing them requires tremendous analytical and researched work. Here, depending on the composition of hydrocarbons, the development of reserves will require the integration of the aforementioned basic technology with physical (wave), thermal (for highly viscous hydrocarbons), gas methods. In the future, obviously, other technologies will be developed (for example, plasma-pulse), which will significantly increase the oil recovery factor. Of course, we will not be able to dwell on the technologies that are widely used today by the Americans, which make it possible to extract about 10% of oil contained in shale oil (natural depletion regimes of deposits) from the depths. This will be a classic dilution of mineral reserves with the creation of enormous difficulties for their further extraction, even with the possible use of future effective oil recovery technologies.

The method of hydraulic fracturing may be the most popular method in the development of oil deposits in shale and similar rocks and, in general, in tight rocks

with a permeability of 1 mDa and below. Without this method, the exploitation of such deposits is currently not even discussed. Other enhanced oil recovery methods can be used after hydraulic fracturing.

As an alternative to hydraulic fracturing, today we can consider a local gas-dynamic fracturing created in the Avangard Design Bureau. LGDF does not need to fix cracks with proppant, it is much cheaper than classic fracturing (6-10 times) and can be used in certain areas of exploited fields with hard-to-recover reserves and especially in conditions of bottom-hole contaminated wellbore zones. The same tasks can be performed by oscillators for treating wells under various names, such as, for example, hydrodynamic well oscillators (Muslimov, 2014).

Hydromechanical wave technologies of the new generation are currently combining one of the new and promising areas of engineering and technology developed for the first time in the world at the Scientific Center for Nonlinear Wave Mechanics and Technology of the Russian Academy of Sciences (Ganiev, 1998).

When choosing a complex of research and technologies for the extraction of hydrocarbons, today we can outline two directions. In most cases, two types of hydrocarbons are present in shale strata: conventional (usually light) oil and kerogen. This can be explained by the conditions of their generation: conventional light oil is of inorganic, kerogen-organic origin. At present, it is obvious that conventional oil is being extracted, since the existing technologies do not allow extracting hydrocarbons of the second group. Therefore, the accepted oil recovery factor (0.08-0.12) refers to the production of this group. For decades, this oil has been extracted at several deposits (mendym-domanic deposits) of the Romashkino field in Tatarstan. They were identified along the way in the wells drilled on sediments of terrigenous Devonian. The potential for increasing oil recovery factor for this group of oils is still available.

Oil production can also be obtained from kerogen through its in-situ processing. Such oil in its usual state is absent in the reservoir and may appear as a result of warming and pyrolysis of the primary kerogen.

At present, the first direction is technically feasible, while the second can only be implemented in the long term.

This requires special, expensive laboratory and field experiments.

However, obtaining information for the implementation of the second direction should be carried out now, using the wells drilled on the terrigenous Devonian, to collect information about the mineral composition of the Sargayevskian-Rechitskian complex, its fluid saturation, OM content, its thermal maturity, and the generation potential of these sediments. All of

these studies, which are currently being conducted, will allow to determine the distribution boundaries of the rocks of the Domanic facies in the section, will give all the necessary information about it and significantly reduce the cost of research of shale strata in the future, when the introduction of technologies for in-situ shale processing will become profitable.

As for just ultra-permeable rocks that make up a significant part of the sedimentary deposits of Tatarstan, here the presence of kerogen is not necessary. There can only be oil of the first group. Accordingly, other technologies are needed that are not related exclusively to intra-layer pyrolysis of HC.

But at this stage, the study of various types of fracturing of the geological environment is the most important. Therefore, it was not by chance that in March 2018 a scientific and practical seminar was held in the Academy of Sciences of the Republic of Tatarstan on the topic "Fracturing and fluid dynamics of the Earth's crust and their role in the formation and development of oil and gas fields". The seminar summarized the experience of studying the fracture of the geological environment in the Russian Federation and outlined further areas of scientific research on the voiced problem. The seminar protocol is given in this issue.

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# Seismic studies of the unevenness of open fracturing and inhomogeneity of the fluid saturation in the geological environment for optimal development of oil and gas fields

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**Abstract.** The distribution of fracturing and the type of fluid saturation in the geological environment, along with its structure, is the most important information for optimal development of oil and gas fields, including their search, exploration and development. Integrated use of seismic information about fluid saturation, fracturing and the structure of sedimentary strata helps to choose the optimal locations for the discovery of wells in order to obtain the maximum possible inflow of hydrocarbons into them. This approach drastically reduces the drilling of dry wells while performing prospecting and exploration works, significantly reduces the capital costs for their implementation and accelerates the commissioning of fields. In the development of the field, continuous seismic monitoring of fracturing and fluid saturation of the productive strata in real time allows the operative optimization of oil displacement schemes and operating modes of wells, choosing the optimal location and time for performing geological and technological measures, and controlling the geological and technical efficiency of their implementation, etc., the rate of recovery and the completeness of the oil extraction from the deposit while reducing capital and operating costs. To study the 2D-4D distribution of fracturing and fluid saturation in the geological environment by scientists and specialists of the “Scientific School of Oil and Gas Seismoacoustics by prof. Kuznetsov O.L.”, innovative seismic technologies are created: “Seismic side-view locator”, “Seismolocation of foci of emission” and “Acoustic low-frequency survey”, in which for obtaining this information, waves of diffuse reflection and microseismic emissions are used, not mirror reflection, as in traditional seismic surveys. As a result of experimental laboratory, well and field studies, the regularity of the amplitude-time parameters of seismoacoustic emission was determined depending on the type of fluid saturation of rocks and physical impacts, which was also used in the technologies of “Logging of seismoacoustic emission” to isolate oil-containing intervals in a section of wells and “Wave treatment of the reservoir” to increase the oil inflow into the well, including hard-to-recover highly viscous oil.

Examples of the application of seismo-acoustic technologies for solving a wide range of applied problems in the development of oil and gas fields are given.

**Keywords:** seismic studies, fracturing, fluid saturation, oil and gas fields

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Uneven and non-uniform fluid saturation (oil, gas, water) of reservoir formations and uneven distribution of open fracturing in the geological environment are extremely important information that is currently not fully or completely used in prospecting, exploration and development of oil and gas fields, which in

turn significantly reduces the efficiency of oilfield development. Optimization of exploration, when the discovery of an oilfield and the selection of drilling sites is carried out using a complex of structural seismic information, data on fluid saturation and fracturing, can significantly increase the “success” of drilling, resulting in drilling of wells with the highest possible flow rate of hydrocarbons. This optimization reduces drilling costs, speeds up the oilfield commissioning and makes them attractive for investment. In confirmation of such opportunities, one can refer to the world statistics of well drilling “successfulness”, which is 30-35% when

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searching for (discovering) an oilfield, and 65-70% when exploring, which indicates on “hidden” reserves to improve efficiency of prospecting surveys.

When developing oil and gas fields, information on reservoir’s fracturing and fluid saturation in the interwell space is obtained from discrete seismic observations or continuous seismic monitoring, which provides real-time results and unlimited in time. In the first case, the information can be used for optimal placement of production and injection wells, which is especially important for fields with a fractured-porous and fractured (usually carbonate) reservoirs. According to our data, at such fields, 10-15% of wells produce 85-90% of oil. This shows that consistently high flow rates in such a reservoir can be obtained if a well accidentally successfully drilled into the zone of intense fracturing (Akselrod, 2013). If these “oilfield’s good places” can be determined from seismic data in accordance with distribution of oil content, fracturing, fluid (oil and water) flows, etc. within the reservoir, then the number of producing wells can be significantly reduced. In the second case, the information obtained in real time continuous monitoring allows quickly optimize reservoir drive mechanisms and well production conditions, select the optimal place and time for performing well stimulation operations and monitor the geological efficiency of their implementation, identify areas of high oil content in the water-saturated part and behind the extent of the reservoir, etc. Solution of these and other development optimization problems allows to significantly increase production and oil recovery rates at an oilfield as well as reduce capital and operating costs.

Innovative seismic technologies such as “Seismic Locator for Lateral Survey” (SLBO-technology, Kuznetsov et al., 2004), “Seismolocation of emission centers” (SLEC, Kuznetsov et al., 2007b) and “Acoustic Low-Frequency Prospecting” (ANCHAR, Arutyunov et al., 1997), as well as acoustic technologies such as “Seismoacoustic emission logging” (SAEL, Kuznetsov et al., 2007b) for identifying oil-saturated intervals within the well section, including identification through the iron and cement columns, penetration zone, and the “Wave Reservoir Stimulation” (WRS, Kuznetsov et al., 2001, Kuznetsov et al., 2007b) increasing the flow of oil (including hard-to-recover and highly viscous) into the well were developed by scientists and specialists of the “Scientific School of Oil and Gas Seismic Acoustics of Prof. Kuznetsov O.L.” to study the 2D-4D distribution of fractures and fluid saturation in the geological environment. Creation and improvement of these technologies was carried out in accordance with the results of theoretical studies and numerous laboratory experiments, well operations and field surveys. The research data allowed to study in detail the processes of fractures formation and seismoacoustic emission waves

occurrence, as well as to establish the pattern of changes in seismoacoustic emission amplitude-time parameters related to the type of rocks fluid saturation and physical impacts. For the first time, there were discovered the sub-vertical zones of intense open fracturing (geodynamic pumps for vertical fluid transfer), it was identified the mini-block structure of the sedimentary sequence, as well as were revealed the lunar-solar phases of the geological environment compaction and decompaction, etc. All the identified phenomena and patterns can be used to improve the efficiency of oil and gas fields development. For example, diffuse reflection and microseismic emission (MSE) waves, rather than specular reflection, as in traditional seismic exploration, are used in such seismic technologies as SLBO, SLEC and ANCHAR in order to increase the geological efficiency of studying fracturing and fluid saturation of the sedimentary sequence. This made it possible to significantly increase the reliability of the obtained seismic information on fracturing and fluid saturation of the geological environment. Below we briefly describe the basics of the scattered reflection and MSE waves generation, and then the most important information about the process of fracturing and the space-time (4D) distribution of fracturing in the geological environment.

### Scattered reflection waves

Diffuse seismic waves (or scattered waves) are formed in the geological environment on irregularities with sizes comparable and smaller than the length of the incident seismic wave. In acoustic terms, an open fracture filled with fluid (gas, water, oil) act as the most contrast heterogeneity. Scattered waves arise on the totality of open fractures (within the 1st Fresnel zone). The amplitude of this wave is dominantly dependent on the intensity of rock fracturing in the area, where this wave was formed. Considering that fracturing exists everywhere in the geological environment (“... there are no non-fractured rocks in nature ...” (Dorofeeva, 1986)), so the scattered waves also occur everywhere. Therefore, the location survey should be used for observing and positioning scattered waves, and the location survey should be lateral to exclude (suppress) the influence of the interference of specularly reflected waves. The energy of scattered waves is in 1-2 orders less than the energy of specularly reflected waves, which determines the need for in-phase scattered wave signals stacking with a multiplicity of  $10^4$ . In order to get such a stacking, the emitting and receiving antennas of the locator should each contain at least 100 emitting and receiving points, respectively. The kinematics of the scattered wave corresponds to a hodograph of a point emitter, which is individual for each viewpoint. This makes it possible to determine the energy of scattered reflection, which corresponds to the intensity of open fracturing,

at a lateral location survey at each scanned point of the geological media. Thus, using Seismic Locator for Lateral Survey and always presenting scattered waves, as well as specularly reflected waves in an artificial seismic wave field, we can obtain information on the spatial (2D and 3D) intensity of open fracturing distribution in the geological environment. Fig. 1 shows an example of such information obtained using the SLBO-technology at the Kuyumbinskoye field in Eastern Siberia

**MSE waves**

MSE and acoustic emission waves exist everywhere and every time in the geological environment. These waves arise due to transformation of elastic energy from a potential form (stressed state of rocks) into kinetic form (elastic waves emitted by these rocks). This transformation occurs in an open fracture (Fig. 2), when the lateral expansion and formation pressure forces stretching the fracture cavity in width begin to exceed ultimate tensile strength of the rock. Then, a discontinuity of the rock occurs at the ends of the fracture, the fracture lengthens closing its banks together and pushing fluid out of the cavity. At this moment, the following two main acoustic waves are formed: the first wave is formed when the cavity collapses and the wave propagates within the rock matrix with a negative (dilatation) first phase, the second wave propagates in a fluid with a positive (pressure increase) first phase. These waves propagating in the nearby space (at a distance of 2-3 wavelengths) provoke adjacent fractures prone to stress relaxation. New waves (together with the previous ones) provoke the adjacent fractures to discharge, etc. A “chain reaction” effect is created when sets of fractures co-operatively form elastic seismic waves in a wide range of energies (from  $10^{-16}$  to  $10^{18}$  J) and frequencies (from  $10^{-1}$  to  $10^8$  Hz) in the geological environment. The intensity of seismic waves is determined by the density of “mature” fractures located in the area of wave formation,

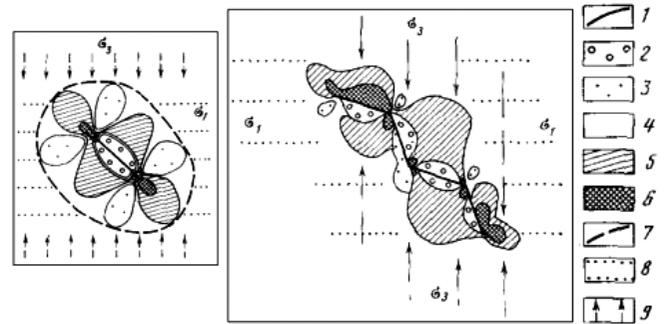


Fig. 2. An example of stress state modeling in the region of a single linear (a) and group zigzag (b) fractures (according to M.V. Gzovskii (Gzovskii, 1975)). 1 – fracture (cut in the model); zones: 2 – the highest decrease in stress, 3 – a slight decrease in stress, 4 – unchanged initial stress, 5 – a slight increase in stress, 6 – the highest increase in stress; 7 – conditional boundary of the signal emission zone; 8 – directions of maximum principal stresses  $\sigma_1$ ; 9 – directions of the minimum principal stress  $\sigma_3$

while the frequency range is determined by the size of these areas (from  $10^{-6}$  to  $10^3$  m). Under natural conditions of the geological environment, acoustic waves are formed in areas of up to one meter, while microseismic waves are formed in areas of up to hundreds of meters.

It is also important to note that each MSE wave emitted in the geological environment has its own individual hodograph on the observation surface. This hodograph corresponds to the wave from a point source located in the hypocenter of the MSE wave generating zone. This relation makes it possible to unambiguously position MSE waves in the geological environment by their kinematic parameters, and make assumptions on the intensity of the fracturing in accordance with their dynamic characteristics.

The time variation of microseismic emission in a discrete volume (“point”) of the geological environment corresponds to a random multiplicative process (Fig. 3), in which the amplitude-time characteristics

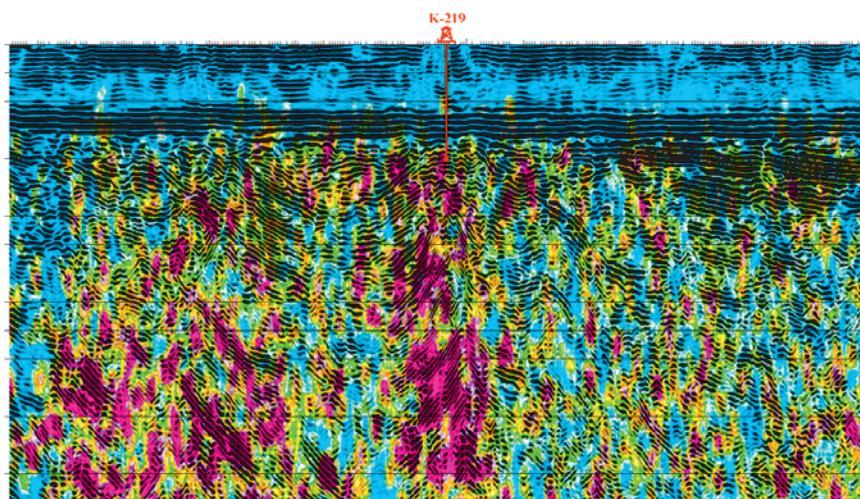


Fig. 1. Vertical sections of the open fracturing field with non-uniform intensity (high is indicated in red, low is indicated in blue) in comparison with the structural factor (black) obtained by scattered and reflected waves, respectively. Kuyumbinskoye field, Eastern Siberia

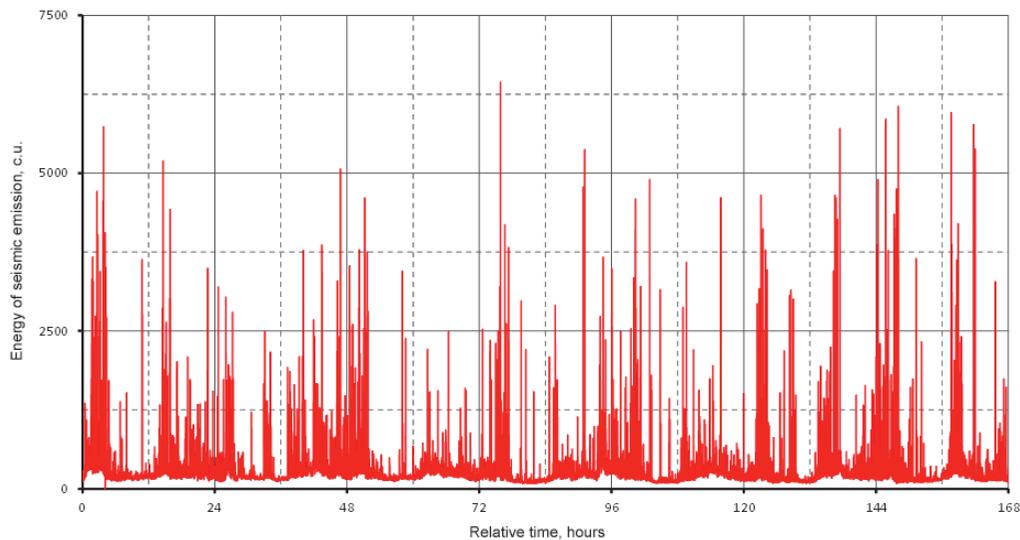


Fig. 3. Random multiplicative process of changing the intensity of microseismic emission in a discrete volume ("point") of the geological environment for 160 hours of continuous observation using the SLEC technology. Duration of discrete processing intervals is 10 s; total number of intervals (emission values) is 5760

of emitted elastic waves discrete signals correspond to the Gutenberg-Richter law or the seismic law of earthquake recurrence (Richter, 1963). This law defines an inverse linear relationship (on a logarithmic scale) between the energy of an emitted signal and the frequency (repeatability) of its emission with a given energy (following the logic of the physical process it can be concluded that the more energy is emitted, the more time it is required to accumulate it). For MSE, this pattern corresponds to signals the amplitude of which exceeds the level of seismic noise caused mainly by technogenic and natural sources generating near-surface interference waves. The lower threshold of the MSE waves intensity is determined by the sensitivity limit of the equipment used for seismic observations. The use of the Gutenberg-Richter law in analyzing the results of seismic monitoring materials processing allows estimation the accuracy of MSE waves identification in the resulting seismic wave field, which is required at the initial stage of interpretation.

In addition to the above pattern, it was found that the amplitude-time parameters of microseismic and acoustic emission vary depending on the type of rocks fluid saturation as well as on physical impact (Kuznetsov et al., 2007a). In case of natural occurrence of rocks with oil saturation, the average energy of a random MSE process is minimal and the dispersion and autocorrelation interval are characterized by maximum values relative to gas saturation, where the average energy is maximum and the dispersion and autocorrelation interval are minimal, as well as relative to water saturation, where these statistical parameters have average values. In case of physical impact (natural and technogenic), the MSE activity increases dramatically in oil-saturated rocks, where the average energy increases multiply. The energy increases in water-saturated rocks by the

first tens of percent and remains almost the same in gas-saturated rocks

These changes in the amplitude-time parameters of seismoacoustic emission (SAE) process, depending on the type of rocks fluid saturation and physical impacts, were experimentally studied in laboratory, downhole and surface conditions. Fig. 4 shows the results of accumulated AE energy laboratory studies for oil-, water- and gas-saturated core samples-clones before and

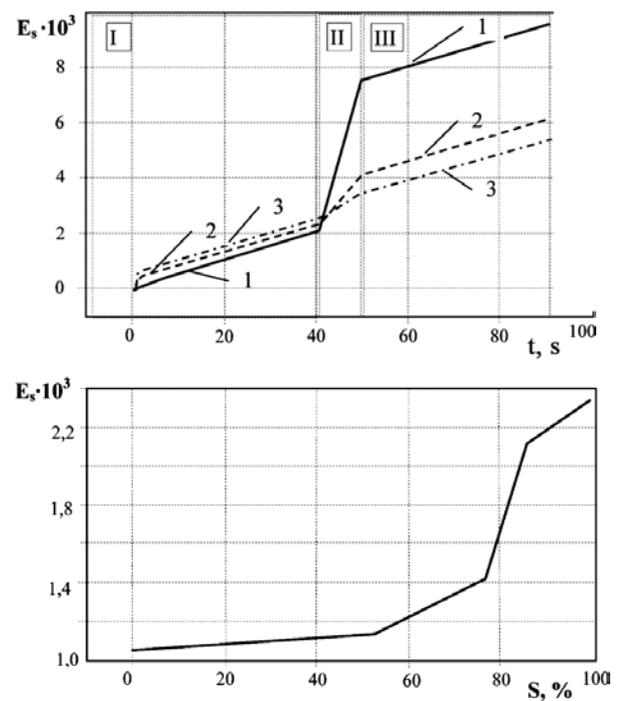


Fig. 4. Results of accumulated AE energy laboratory studies for oil-saturated (1), water-saturated (2) and dry (3) core samples-clones under load (top) and changes in AE energy from sample's oil saturation (bottom). I – when applying a mechanical load, II – when applying an impulse-wave impact, III – after impact

after its loading, as well as changes in AE energy from the uneven oil saturation of the sample.

The following main factors and conditions define the pattern of change in the amplitude-time parameters of elastic energy emission. In case of natural occurrence of the reservoir in statically uniform conditions, when identical rocks with a single reservoir pressure occur at the same depth, the nature of the emission is determined by the type of saturating fluid, the viscosity of which for the gas-water-oil sequence increases from  $10^{-5}$  Pa·s (for gas) up to  $10^2$  Pa·s (for high-viscosity oil). If the reservoir is saturated with oil, then there is rare emission of signals with relatively high energy and low-frequency spectrum, if the reservoir is saturated with water, the emission is more frequent, but its energy is lower and spectrum is more high-frequency, and if the reservoir is saturated with gas, then emission frequency and spectrum of discrete signals are even higher however its energy is minimal. Such an amplitude-time characteristic of discretely emitted signals determines the above statistical parameters, their gradation depending on the type of saturation.

At the event of geological environment activation, in case of tensile forces increase (for example, when reservoir pressure increases due to hydraulic fracturing) and/or in case of fluid viscosity decrease (for example, under acoustic or thermal effects), the SAE process in oil-saturated rocks is also gets activated/ This process is characterized by increase in frequency of discrete elastic signals emissions and also by increase in their energy. This in turn changes the value of probabilistic average of a random process for oil-saturated rocks, which becomes maximal in relation to emissions in case of water and gas saturation. It should be noted that the effect of SAE enhancing under wave impact on oil-bearing formations and oil fields (there is no such an effect for gas fields) is used in some seismic acoustic methods of “direct prospecting”. For example, in SAEL and ANCHAR, the wave impact is used to reduce the time of emission observation (monitoring). In the method of G.V. Vedernikov (Vedernikov et al., 2011) the appearance of MSE waves on CDP seismograms is used as a sign of the presence of an oil reservoir; The “Bright Spot” and “Adaptive Vibroseismic Prospecting” methods (Zhukov et al., 2011; Zhukov, Schneerson, 2000) use a concept, where oil reservoir can be identified by the effect of a significant increase in the reflected wave amplitudes from the productive strata due to MSE energy.

Thus, MSE waves are a reliable indicator of the type of fluid saturation, as well as an indicator of geological environment open fracturing in case of long-term continuous passive seismic wave field monitoring. However, the intensity of the MSE waves is low. It is 1-2 orders of magnitude less than the intensity of surface

interference waves. This fact determines the need for the in-phase scattered wave signals accumulation with a multiplicity of more than  $10^4$ . The principle of passive seismic locator is used to implement such accumulation stacking. The receiving antenna (aperture) of such locator should contain at least 400 receiver channels, and the duration of the discrete processing interval should be more than 100 estimated MSE wave periods, i.e., about 6-10 seconds. Thus, given that the MSE occurs everywhere and constantly in the medium, the procedure of wave field localization in a large time window makes it possible to determine the average intensity of the elastic energy emission at the focal points in a given time interval. All these methods of seismic wave field observation as well as the identification of MSE waves and their positioning in geomedias are implemented in “Seismolocation of emission centers” (SLEC) technology.

In the SLEC technology, an increase in the signal-to-noise ratio (SNR) occurs not only  $n^{0.5}$  times, where  $n$  is the number of receivers in the locator antenna (surface monitoring array), but also due to stacking in time of  $m^{0.5}$  times, where  $m$  is the number of MSE waves with a period  $T$  in the time window  $\Delta t$ , which is  $m = \Delta t/T$ . In general,  $SNR = (n \times m)^{0.5}$ . For example, in case of antenna with  $n = 400$ ,  $\Delta t = 8$  s and  $T = 0.08$  s, we obtain  $SNR = 200$ . Similar MSE waves accumulation at each observation point at one iteration (duration of  $\Delta t$ ) and subsequent statistical processing of the MSE process on the total duration of monitoring ( $t$ ), i.e. with representativeness of the sampling  $k = t/\Delta t$ , which is more than 105 discrete values of the average (for iteration) MSE energy, makes it possible to calculate average value, variance and autocorrelation function (ACF) in the field of statistical parameters of the random emission process, while the random noise is almost absent. In this case, the average MSE energy field is identified with open fracturing distribution, and the field of the normalized ACF parameters is identified with the oil-saturation distribution in the geological environment.

### Fractures distribution in the geological media

The distribution of fracturing in the geological environment is determined by its stress-strain state. In any area of the geological environment there is a large variety of multi-scale deformations and sources of stress. The main ones can be considered as:

- *global* caused by oscillations of poles and speed of the Earth's rotation;
- *regional* caused by the movement of lithospheric plates (plate tectonics);
- *local* caused by crystalline basement blocks movements and deformation of the sedimentary sequence.

These numerous stress-strain state sources create their own specific fracture systems in various parts of the



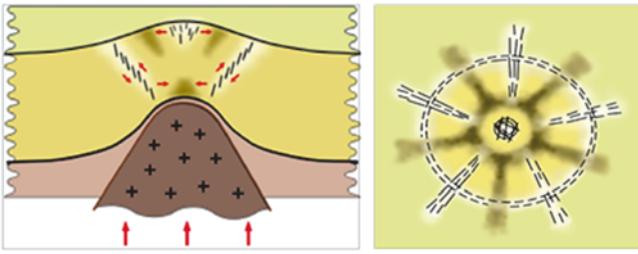


Fig. 6. Tectonophysical model of fracturing and compaction zones distribution on an anticline structure in vertical section (left) and horizontal section (right)

vectors. And given that the main vector of compression in the geological environment corresponds to lithostatic pressure, the vast majority of fractures in the geological environment are subvertical. In addition, taking into account that the lithostatic pressure increases with depth, then the intensity of open fracturing increases accordingly with depth. Moreover, positive and negative anomalies corresponding to intervals of more brittle (carbonates) and more ductile (salt, clay) rocks can be identified in the sedimentary layer against the overall growth of fracturing with depth.

The aforementioned dilation effect (compaction and decompaction zones paragenesis) is also an important regularity in the distribution of fracturing in the geomeidia, which should be taken into account when interpreting the results of processed seismic materials obtained during multi-stage hydraulic fracture monitoring (MHF).

According to the results of numerous studies, it was noted that in the geological environment the distribution of fractures in their size and number (with given size) corresponds to an inverse linear relationship on a logarithmic scale, i.e. Gutenberg-Richter law (Richter, 1963). This indicates on the absence in the geological environment of single fractures (ruptures) having large dimensions of hundreds of meters without smaller fractures accompanying them. There are fracturing zones in geoenvironment, in which there are both a multitude of small and large fractures with maximum sizes, which were formed at the coalescence and connection of small, medium and large fractures. Therefore, as the main model of MSE seismic hydraulic fracture monitoring interpretation should be considered not a single symmetrically diverging (from the wellbore) fracture, as is customary for fracture modeling in an isotropic medium, but a fracture zone consisting of open fractures of various sizes, including main mega-fractures. This model allows estimation of size, configuration, azimuth, etc. of both the zone itself, and major fractures in it.

### Fractures change over time

The time factor influences the process of fracturing and transformation of fractured zones in the geological

environment. These changes can be associated with both geological and current time intervals.

*In geological time*, open fractures are usually become resistive in case of aqueous solutions flow through the cavities of the fractures, which generates post-sedimentation processes, secondary minerals deposition, etc. In this situation, the cavities are filled with resistive material closing the fractures. As a rule, a set of closed fractures form the zone of compaction in the geological environment including reservoir. This zone becomes a screen for the flow of fluid, although it was previously the main fluid flow line. At the same time, in the subsequent geological time in this zone there is no open fracturing with the same strike as the closed one. In that case it is possible the formation of open fractures with orthogonal direction of the strike. It is also interesting to note the fact that at present extended zones of geological environment disruption (faults, fractures, etc.) formed during the past geological time are usually represented in their middle part by closed fracturing, and at the ends are open, which indicates possible development of the fault.

Open fracturing undergoes constant changes in contrast to closed fracturing. This is due to the unstable state of open fractures, their periodic opening and collapsing, constant accumulation and emission of elastic energy. Open fractures (or open fracturing zones) are constantly changing their shape, structure and location. Dynamics of these changes over time is determined by the gradient of space-time (4D) change in the stress state of the geological environment. A good example presented in Fig. 6, is the increase in the activity of the fracturing process (according to MSE data) in the time interval of the maximum Earth's gravity gradient caused by solid-state Lunar-solar tide. In the period of the high tide, when the moon is at its zenith, the medium is compacted due to partial collapse of open fractures, and at low tide (the moon is in a nadir); the geo-medium is softened due to the increase in open fracturing. This effect is illustrated in Fig. 7, which shows the graphs of the change in time of the MSE intensity (top) and the Earth's gravity gradient (bottom) over the study area. There is a good synchronicity of changes in these parameters, which indicates the real existence of compaction and decompaction phases of the geological environment during solid-state Lunar-solar tide effects. It should be noted that the full period of the lunar-solar compaction-decompression of the geological environment is the lunar day and is a kind of "Earth's breath" (Kuznetsov et al., 2006b, Kuznetsov, Lyasch et al., 2016).

According to our experience in seismic hydraulic fracture monitoring, the phenomenon of lunar-solar geomeidia compaction-decompaction has an impact on the process of technogenic fracturing. An open fracturing zone with the maximum possible area dimensions is

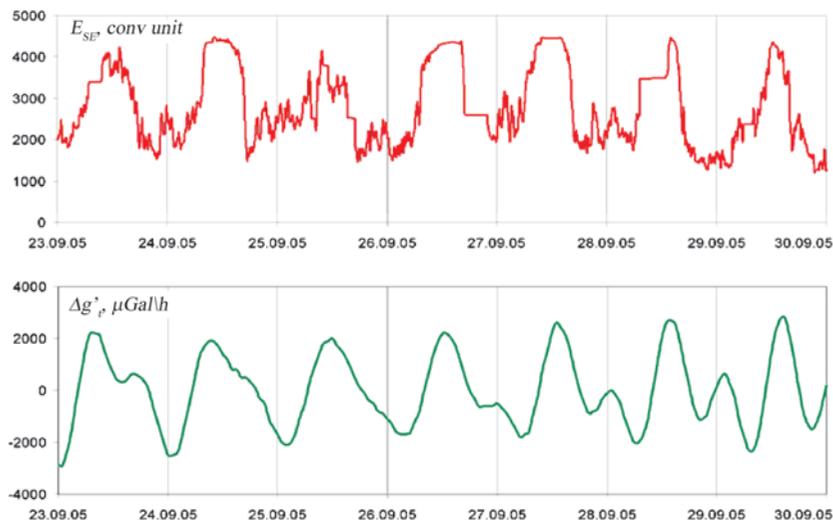


Fig. 7. Comparison of the averaged (moving average) MSE waves energy (top) and the temporal Earth's gravity gradient within the oil field (bottom)

formed in the time decompaction phase, while the area dimensions are minimal in case of compaction phase. In the latter case, some problem situations arose with the injection of proppant into the reservoir during the geomechanics compaction, which should also be taken into account when choosing the timing of hydraulic fracturing.

The lunisolar phases of geomechanics compaction and decompaction act as a peculiar geodynamic pump mechanism, the subvertical fracturing zones, which permeate the entire sedimentary cover and often evolving from the basement. Taking into account that the size of these zones can be on average 1 km in diameter and 5 km in height, considering fracture porosity of 0.1% and daily changes in the intensity of the fracturing for the geological environment (according to the results of our research) of 15%, then the total volume of intake and squeezing fluid will be about 0.5 ml m<sup>3</sup> per day. When the pump is operating, this volume of fluid moves mainly from bottom to top along the zone and entering the reservoirs. If we consider that the pump is quite "leaky" (fractured), then not all of the calculated fluid volume is pumped into the reservoirs. But still, 0.1% of this volume is enough to carry out the effect of a mini-fracturing operation every day, i.e. generate flushed lines for fluid (water and oil) movement. Moreover, taking into account the differences in density, philicity and phobicity of the fluid and rocks, the flushed highways (the main channels of water and oil movement) will be different, and in case of its crossing, there will be observed a blockage of one of the fluids (most likely oil) movement.

As an example, Fig. 8 shows the diagrams of the main flows of water and oil identified in the field of MSE gradients average energy and dispersion respectively compared with the oil production forecast for the entire oilfield area at the current monitoring period. The diagram clearly shows the blocking of oil

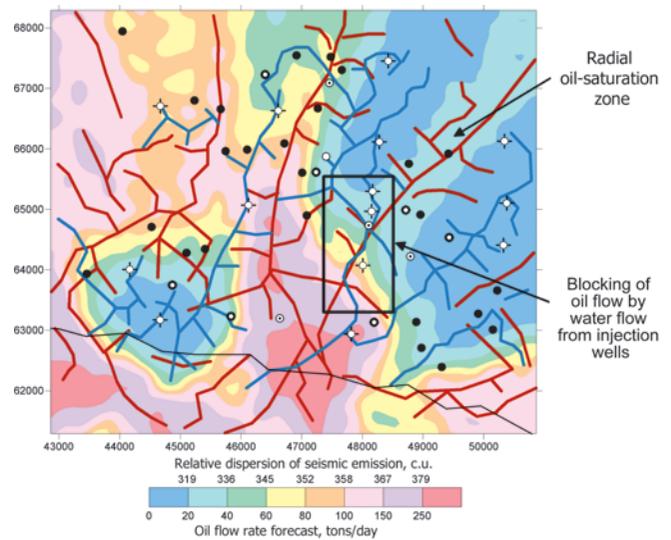


Fig. 8. Diagrams of the main flows of water and oil identified in the field of MSE gradients average energy and dispersion respectively compared with the oil flow rate forecast for the entire oilfield area at the current monitoring period. Rostashinskoe oilfield, Orenburg region

flow coming from the geodynamic pump by the flow of water in the eastern part of the field. Due to the blocking of the oil flow, there is a low oil saturation of the northeastern zone and a low oil flow rates of the producing wells located here. In order to unblock the oil flow, it is necessary either to temporarily stop injection wells, or to set injection to cyclic flooding mode. The radial zone in the northern part of the area should be considered as an example of successful matching of fluid flows. The production wells located here have a maximum production rate.

Fig. 9 shows the correlation between the values of the current flow rate and the variance of the MSE process on the basis of which an oil production rate was predicted for the entire field area (Fig. 8) as well as identified the primary production wells, in which well

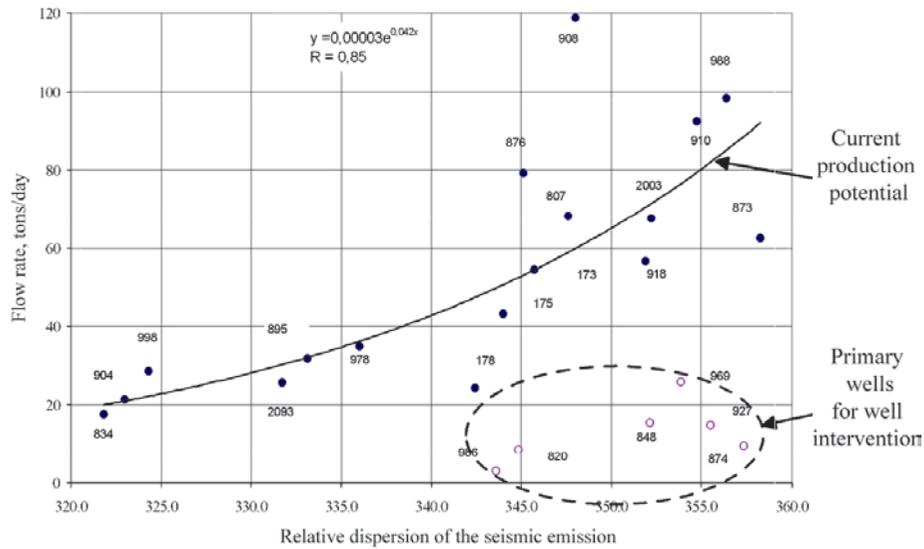


Fig. 9. Correlation between the values of the current flow rate and the dispersion of the MSE process

stimulation operations would allow a multiple increase in production rates.

**Identification of scattered and MSE waves by 3D seismic data processing**

Further improvement of the SLBO and SLEC technologies allowed the processing of initial CDP-3D seismic materials based on the algorithms of the lateral and normal location surveys. The first direction of processing was previously used to identify scattered waves and construct a fracturing cube based on CPD-3D initial data. The results of the second direction are presented for the first time after numerous experimental studies on different exploration areas. Fig. 10 shows CDP-3D seismic survey standard acquisition system

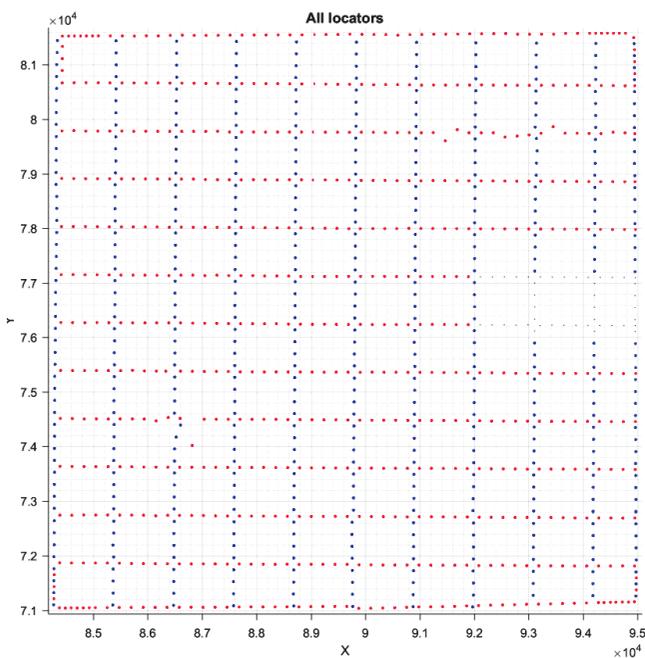


Fig. 10. CDP-3D seismic survey standard acquisition system (receiver points are shown in blue, shotpoints are shown in red)

at one of the areas in Texas, USA. Open fracturing cubes for diffuse waves and oil content for MSE waves were obtained according to the results of the materials reprocessing. Fig. 11 shows the slices of the open fracturing intensity and oil content along the Sligo horizon. Fig. 12 shows the vertical graphs of fracturing and oil saturation along the Cooke-3 wellbore. The graph shows (down to the bottomhole depth of 14 thousand feet) the oil-containing intervals of the section, which were identified during the well drilling, indicates the reliability of the results obtained. According to the results of oil content distribution in the Sligo formation, there is an oil-saturated part of reservoir limited in the north by a sublatitudinal normal fault, which act as an impermeable screen. This normal fault is not indicated on the structural map; however, it can be clearly seen on seismic time slices. In addition, within the oil-saturated area (Fig. 11, below), there is a good correspondence between the minimum oil saturation and the local synclinal areas bounded by the 13150-ft hypogype located in the central-eastern and north-central parts of the area. It should be noted that this interrelation (of structural factor and oil-saturation) was identified from independent information, the reflected and emission waves.

**Conclusion**

Since the 70s of the last century, scientists and specialists of the “Scientific School of Oil and Gas Seismic Acoustics of Prof. Kuznetsov O.L.” have been carried out theoretical and experimental seismoacoustic studies of fractures and fluid saturation distribution in the geological environment. Since that time were created some special methods and technologies, which, as they were applied, were constantly improved to increase the efficiency of their use and the reliability of the geological environment characteristics studying results. It was found that the most reliable results of fracturing identification by seismic studies can be obtained by

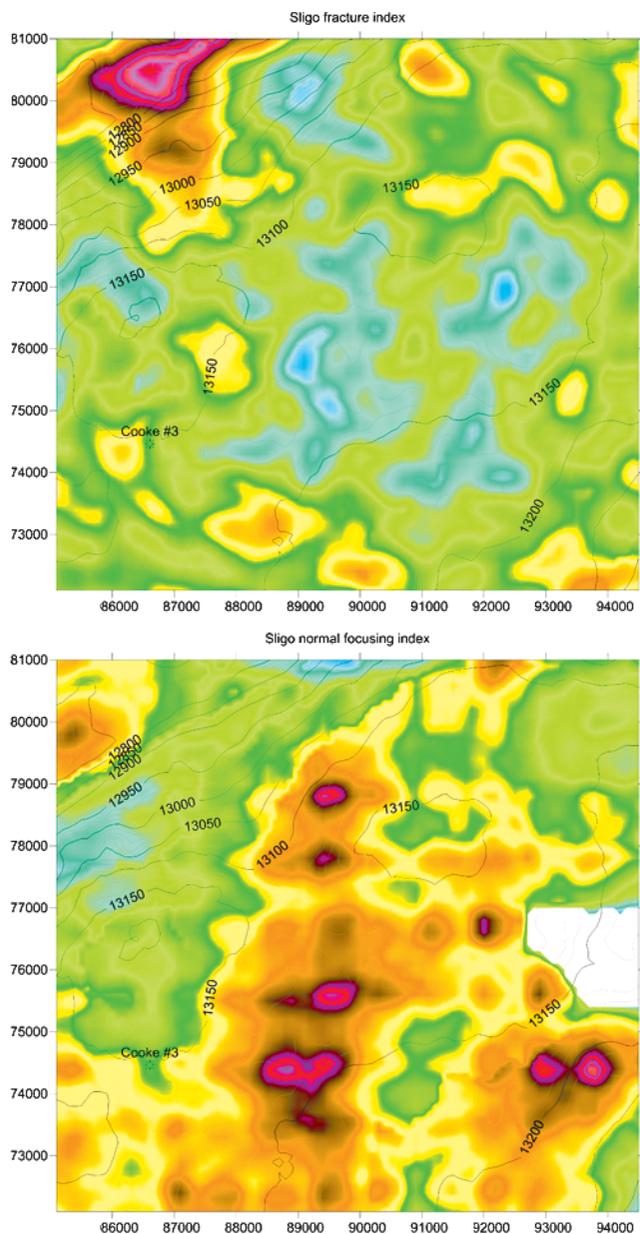


Fig. 11. Open fracture intensity (top) and oil-bearing capacity (bottom) slices along the Sligo structural horizon

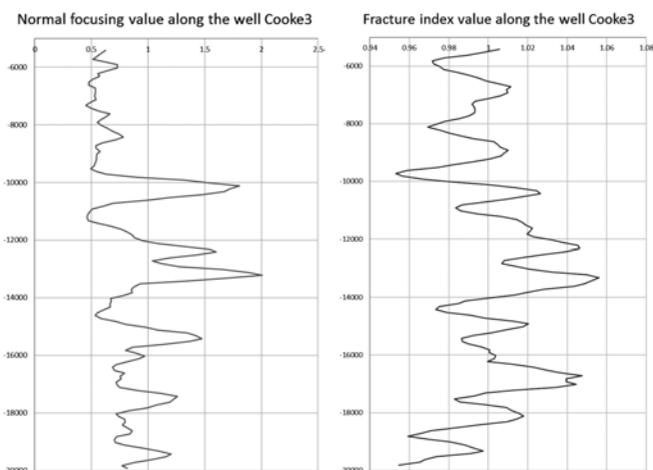


Fig. 12. Vertical graphs showing fractures (left) and oil saturation (right) along the Cooke-3 wellbore

diffuse reflection waves, while the type of fluid saturation can be identified by microseismic emission waves (Kuznetsov et al., 2006a; Chirkin et al., 2014).

The creation of technologies for seismoacoustic 3D and 4D fracturing distribution studies made it possible to identify a number of regularities and peculiarities associated with the presence in the geological environment of:

- Stress-strain state (tectonophysical models);
- Sub-vertical zones of open fracturing (“geodynamic pumps”);
- Mini block (“platy”) structures of the sedimentary sequence;
- Lunisolar phases of compaction and decompaction (“breathing”) of the Earth’s crust;
- Compaction and decompaction zones paragenesis (dilation effect), etc.

All these features of fracturing distribution in the geomeia are taken into account when interpreting the results of fracturing studies in order to solve important applied problems of choosing the well location aimed to obtain the maximum possible inflow of hydrocarbons, predicting hazardous drilling intervals and control of fracturing changes under technogenic impact on the formation, etc.

It was also identified the effect of fracturing on acoustic and microseismic elastic energy emission and patterns of change in the emission process amplitude-time parameters depending on the type of rocks fluid saturation (gas, water, oil) as well as physical impact on them of natural and/or technogenic nature. Based on the revealed regularity, the SLEC technology was created, the ANCHAR technology was improved and the regularities of the “direct prospecting” effects in other seismic technologies were established: “bright spot”, approach of Vedernikov G.V. et al. Currently, based on the SLEC technology, it is possible to implement both special processing of initial 3D data to obtain information on the oil-saturation of the geological environment, and continuous real-time monitoring of changes in heterogeneity and unevenness of fluid-saturation during oilfield development. Such a possibility of the SLEC technology allows solving a wide range of important applied problems in the prospecting, exploration and development of oil and gas fields, while the integration of SLEC with CDP and SLBO technologies significantly increases the reliability of solving these problems.

This paper presents examples of solving only some (of a large variety) of applied problems, many of which were not previously determined for seismic exploration due to its great limitations, since in traditional seismic technology, CDP-3D, uses only reflected waves for solving geological problems, on the basis of which it is possible to obtain reliable information only about

the structure of the geological environment. Therefore, the complex use of seismic waves of a different class (reflected, scattered and emission) observing, identifying and positioning on the basis of complex technological solutions, makes it possible to efficiently optimize oil and gas fields development.

Created and successfully using (in Russia and abroad) seismoacoustic SLBO, SLEC, ANCHAR and GDP technologies awarded the Russian Government Prize in the field of science and technology in 2008, which indicates recognition (at the governmental level) of their effectiveness in oilfield exploration and development and also the expediency of their widespread introduction into the practice of geological exploration and oil and gas production.

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# Method selection of microseismic studies depending on the problem being solved

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The article compares two methods of microseismic studies of the maximum likelihood method and the Capon method for detecting the position of microseismic event when observed from the surface in the conditions of the developed deposit or by monitoring the hydraulic fracturing. The results of computational experiments for determining the accuracy of localization of model microseism in space, as well as for various noise levels, for various types of microseismic events and for the allocation of recurring events are presented. Based on the results of the experiments, the conclusion is drawn that the problems of identifying non-recurring events are more confidently solved by maximum likelihood methods, while for the detection of zones of increased fracturing, the method of Capon is best suited.

**Keywords:** hydraulic fracturing monitoring, natural fracturing monitoring, microseismic events, maximum likelihood method, superresolution method, Capon method, seismic moment tensor

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## Introduction

Microseismic events location is increasingly used in oil and gas geophysics for solving various geological and technological challenges. The main areas of microseismic technologies application are natural fractures monitoring and hydraulic fracture monitoring aimed to optimize the subsequent oilfield development. Natural fractures monitoring allows identify zones of increased fracturing, where the obtained information is used to optimize wells spacing grids. Determination of both hydraulic fractures and natural fractures direction is of great interest for solving problems of geomechanics.

Obviously, such a variety of challenges cannot be solved by only one method and even one approach of microseismic sources location. There are a rather large number of known location techniques (Anikiev et al., 2014; Gajewski et al., 2007; Gajewski, Tessmer, 2005; Gharti et al., 2011), several studies were devoted to compare them (Kushnir et al., 2014; Maxwell, 2014). Unfortunately, the comparison is often done without taking into account the problem being solved, the noise situation and the accuracy of information on the environment velocity characteristics. Below we present a comparison of the two most popular approaches

of microseismic sources location for solving various problems, as well as making some conclusions on the optimal area of their application.

## Known theoretical approaches to microseismic sources location

Currently, there are two approaches to microseismic events location. The first approach includes diffraction stacking methods (Anikiev et al., 2014; Gajewski et al., 2007), time reverse modeling (Gajewski, Tessmer, 2005; Gharti et al., 2011) and maximum likelihood methods (Biryaltsev et al., 2017) allowing to restore the intensity of microseismic events in space and time up to the accuracy of signal sampling rate at a receiver. This approach is used for identification of microseismic sources location directly by readings of the field signals.

The second approach (Kushnir et al., 2014), which is known as super-resolution methods or spectral methods, is based on microseismic sources location on a finite duration signal accumulated over its time interval, where the location can be performed only after signal accumulation. In this case, time of microseismic event occurrence is determined with an accuracy of the accumulation interval, however, the accuracy of microseismic event spatial coordinates determination is significantly higher in comparison with the methods of the first approach.

Differences in these two approaches can be clarified by considering the mathematical assumptions underlying these approaches. For generality, we will consider a

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microseismic event using the seismic moment tensor introduced by Aki and Richards (Aki, Richards, 1980), which allows combining fracture opening and closing with shear displacements in one microseismic event.

Let's denote the magnitudes of the seismic moment tensor components as  $M_i$ , where  $i$  is a particular seismic moment tensor component. Imagine an array of  $k = 1..K$  sensors and denote the recorded signal as  $z_k(t)$ . The recorded signal can be considered as the sum of the noise  $n_k(t)$  and the useful signal  $s_k^i$  from a microseismic event with a magnitude  $M$ :

$$z_k(t) = n_k(t) + \sum_i M^i s_k^i(t) \tag{1}$$

Covariance matrix of the signals vector  $Z$  recorded at each sensor has the following general form:

$$\begin{aligned} cov(Z) = cov(N + \sum_i M^i S^i) = cov(N) + \\ + cov(N, \sum_i M^i S^i) + cov(\sum_i M^i S^i) \end{aligned} \tag{2}$$

Complete covariance matrix in (2) consists of a noise covariance matrix, a signal covariance matrix and a mutual noise and signal covariance matrix.

The mutual covariance matrix is a scattering matrix and we assume it zero in case of active microseismic sources location. In the first approach, we assume that the signal covariance matrix is negligible and the field signal covariances are due only to the noise covariance. In the second approach, we assume that the signal covariance is greater than the noise covariances and the covariance matrix of the field signal with sufficient accumulation time corresponds to the covariance of the useful signal from a microseismic event.

For the first approach, the maximum likelihood method is the most common technique including, as special cases, the methods of diffraction stacking and time reverse modeling. In (Biryaltsev et al., 2017) it was shown that it is possible to determine the seismic moment tensor by solving the following system of equations:

$$\sum_k a_{1k} M^k = b_1 \tag{3}$$

where

$$a_{1m} = \sum_{i=1}^N \sum_{j=1}^N C_{ij}^{-1} (s_i^m s_j^1 + s_j^m s_i^1) \tag{4}$$

$$b_1 = \sum_{i=1}^N \sum_{j=1}^N C_{ij}^{-1} (z_i s_j^1 + z_j s_i^1) \tag{5}$$

Thus, if we neglect the covariance matrix of the useful signal, then the equations for the seismic moment tensor components are linear and can be solved relatively easily.

It is also obvious that such a solution is not applicable to the second approach, since in this case the covariance matrix of the field signal depends nonlinearly on seismic moment tensor components. For the second approach, we are forced to assume for the time being that the microseismic event source is isotropic, all tensor components of which are equal.

Super-resolution methods are based on the following approach: from the field data, we have the  $cov(Z)$

covariance function, which consists of the useful signal covariances. The vector of the simulated signal  $S(r)$  is constructed depending on the position of the source in the space  $r$ , and the value of the test function is constructed for a set of positions  $r$ :

$$F(r) = \frac{1}{S(r)cov(Z)^{-n}S(r)} \tag{6}$$

The maximum of  $F(r)$  corresponds to the position of a microseismic event source. The  $-n$  exponent of the covariance function corresponds to different methods in the framework of the super-resolution approach,  $n = 1$  corresponds to the historically first and most noise-resistant super-resolution method, the Capon method.

### Computational Experiments

For a practical comparison of the first and second approaches applicability in solving various geological and technological challenges, a number of computational experiments were carried out with both maximum likelihood method and the Capon method as the most typical representatives of both approaches. Both methods were implemented in accordance with the stated formulation. A model experiment was carried out for the case of a homogeneous medium with a velocity  $V_p$  under the following conditions (Fig. 1).

An array of 225 model sensors were located evenly over an area of 1 square kilometer. Signal source was placed under the center of the area at a depth of 500 meters. The signal position was identified along the same grid in the source plane in 4 planes above and below the source with a vertical step of 50 meters. The model source function is Puzyrev wavelet with a central frequency of 25 Hz.

In the first experiment (Fig. 2) was tested the statement about a higher resolution of the super-resolution methods compared to the maximum likelihood method. Indeed,

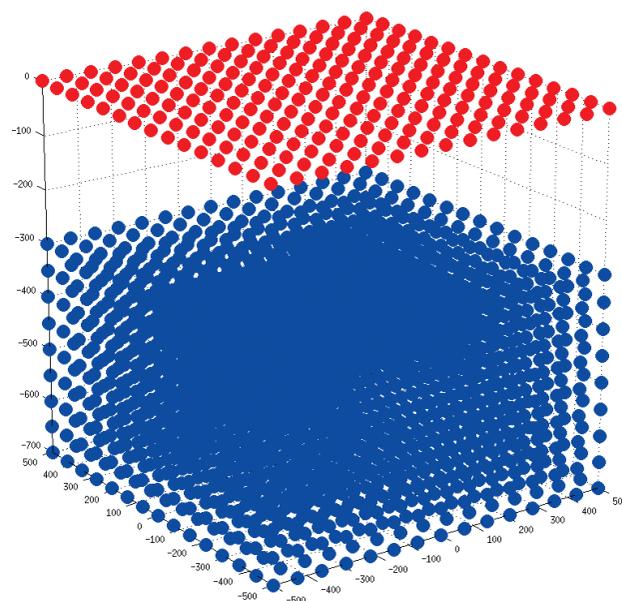


Fig. 1. Computational experiment scheme

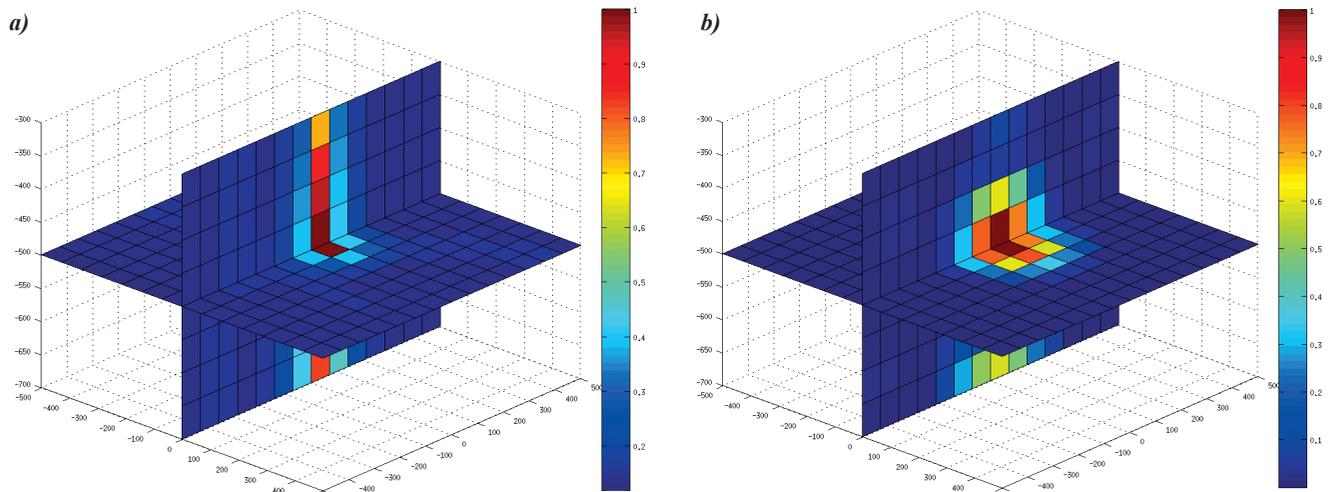


Fig. 2. Accuracy of localization of the model microseism by the methods of Capon (a) and maximum likelihood (b) in space for a low noise level

the area of microseismic event localization in the plane of the source looks more delineated, however, vertical smearing of this area is significantly higher than that of the maximum likelihood method.

The second experiment was conducted in order to compare the noise immunity of the Capon methods with Maximum Likelihood method in the horizontal plane of a microseismic event. The top group of images in Fig. 3 corresponds to the Maximum Likelihood method, the bottom images corresponds to the results obtained by Capon method. The signal-to-noise ratio corresponds to 1/7, 1/12, 1/17 from left to right, respectively.

It can be seen that at low noise level, the intensity of

microseismic event location zone by the Capon method is much higher than that of the maximum likelihood method; however, as the noise level increases, the Capon method sharply loses its accuracy; in case of further increase in noise, the real source is not located. On the contrary, the maximum likelihood method demonstrates a gradual decrease in intensity of microseismic source location area with a moderate level of artifacts for all the noise levels studied.

The following computational experiment was carried out to determine the possibility of microseismic event location for various types of microseismic events. As can be seen in Fig. 4, isotropic and tension crack events

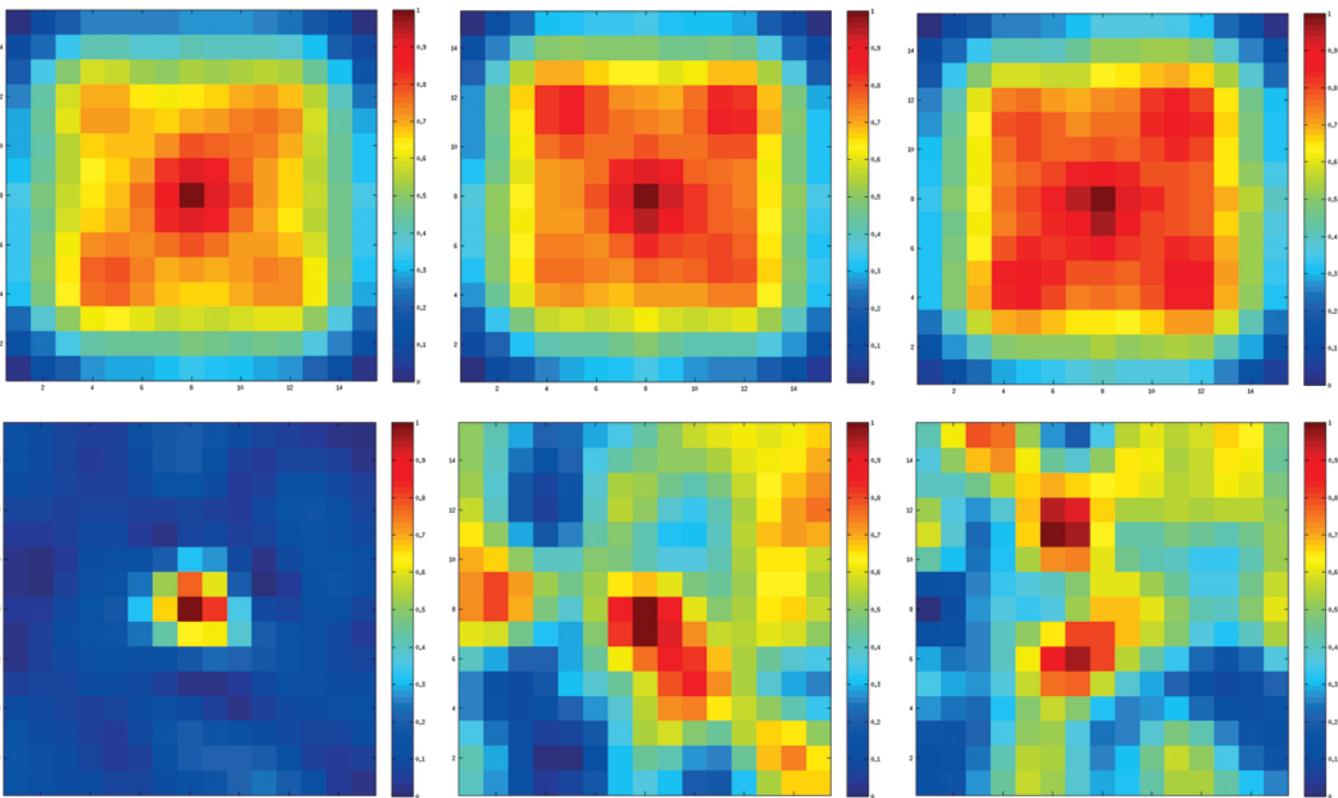


Fig. 3. Comparison of localization accuracy of microseisms by the Capon method and the maximum likelihood method for different noise levels

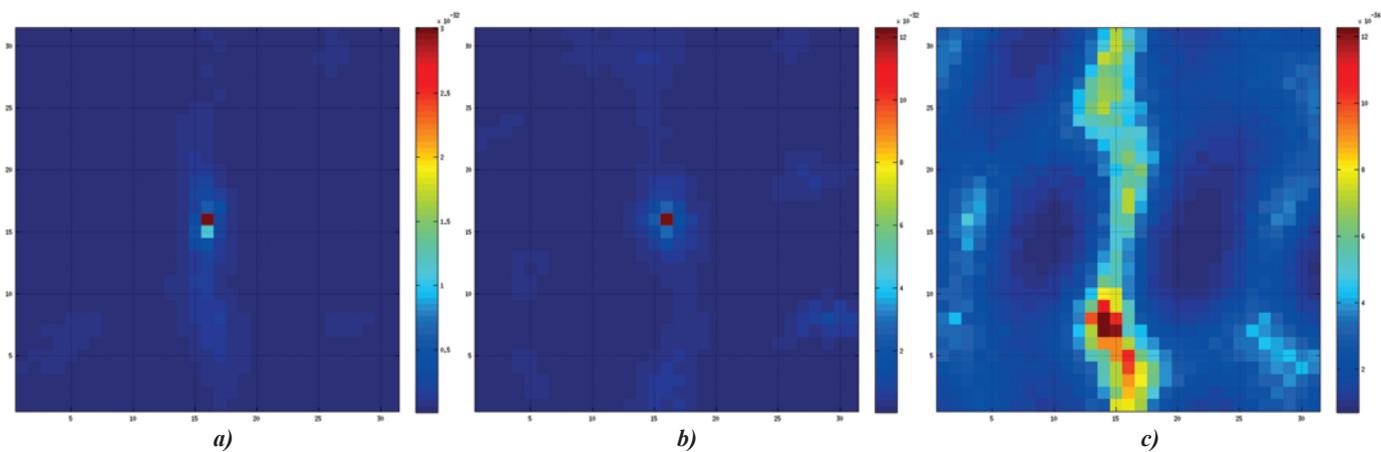


Fig. 4. The localization of various types of events by the Capon method: isotropic (a), tension crack (b) and shear-type (c)

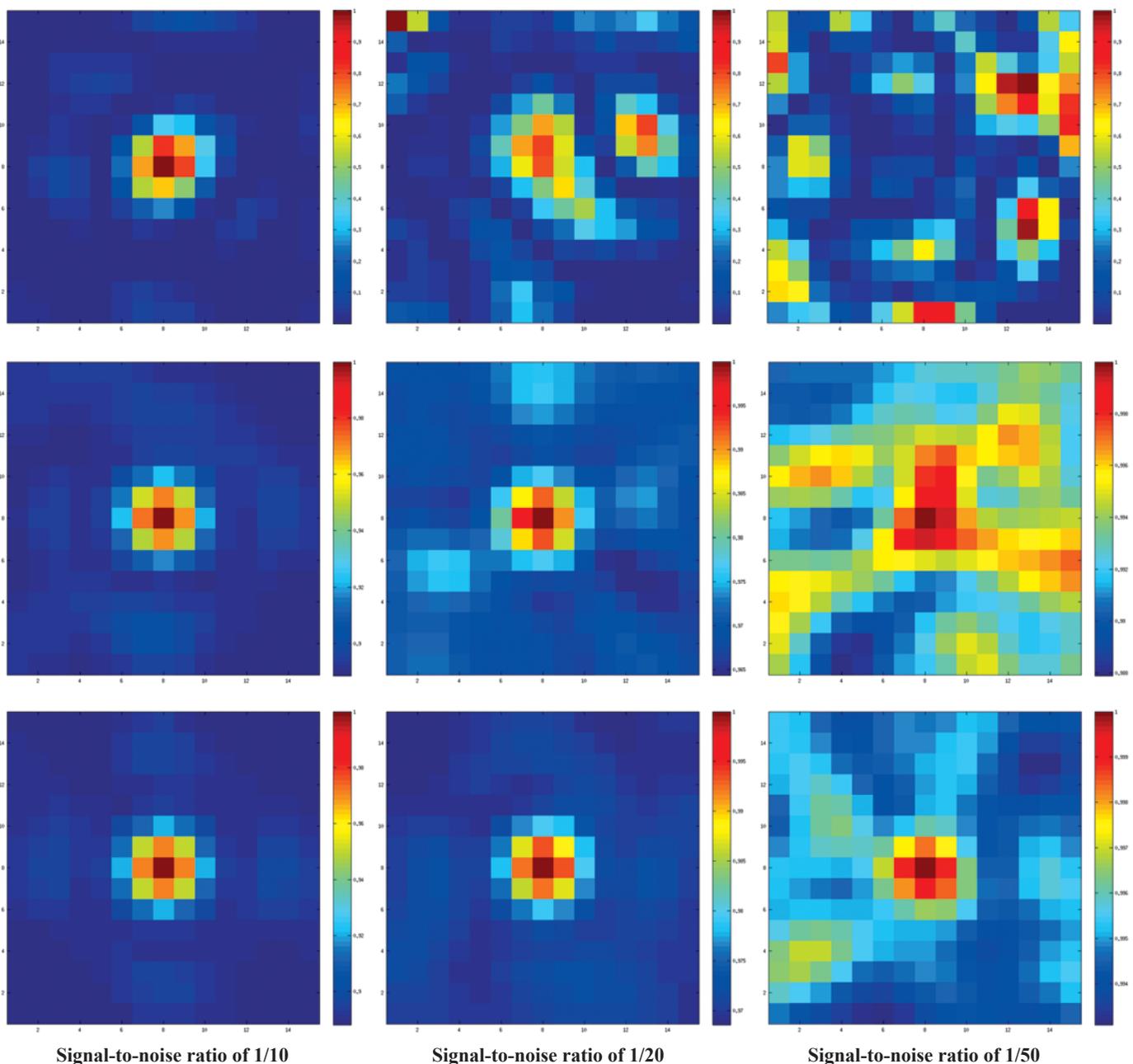


Fig. 5. Comparison of the maximum likelihood method (top row) and the Capon method with an accumulation time of 15 minutes (middle row) and 2.5 hours (bottom row) for different signal/noise levels

are accurately located, however a shear-type event caused the appearance of an elongated artifact with a maximum at a considerable distance from the real place of the event.

The above experiments were performed with single events. In some cases, microseismic events have a recurring pattern, for example, during an event of natural fracturing or long-term impact on a reservoir by water flooding or thermal methods.

In the last experiment, the noise immunity of maximum likelihood and Capon methods were compared on example of recurring events location. A pseudo-field signal consisting of white noise and aperiodically appearing model signals was simulated for this experiment. Experiments were conducted with signal-to-noise ratios of 1/10, 1/20 and 1/50. The maximum likelihood method was used to identify individual signals aimed to get the best location accuracy option, and the Capon method was used with two accumulation times of 15 minutes and 2.5 hours of model time. The result is shown in Fig. 5. It is clearly seen that with a decrease in signal-to-noise ratio, the maximum likelihood method is characterized by the presence of artifacts and the useful signal is not detected with increasing noise level. The only way to improve the noise immunity of the maximum likelihood method in this case is to increase the number of sensors. The Capon method allows improving noise immunity by increasing the accumulation time.

## Conclusion

The experiments have shown that both studied approaches are not universal. The problems of non-recurring events identification, especially in case of high surface noise conditions, e.g. hydraulic fracture monitoring, are more confidently solved by the maximum likelihood method, allowing to calculate the seismic moment tensor, which makes it possible to identify the source mechanism of microseismic event as well as direction of the corresponding fracture caused the event.

Identification of fractured zones, especially when the target horizon is known, and the challenges of flood

zones monitoring and thermal effects on the formation are more confidently solved by super-resolution methods such as the Capon method.

The most complex and challenging tasks, such as natural fracturing direction identification should be solved by the combined application of both methods.

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# Regularities in the development of fracturing zones in rocks of the sedimentary cover of Western Siberia, based on the results of the application of the OilRiver technology, horizontal well logging and hydrofracturing data

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**Abstract.** The article presents known results of theoretical and experimental works, describing the regularities of the formation of fractured-block structures in platform areas. The above examples of mapping such structures in Western Siberia on the basis of the use of the OilRiver technology fully correspond to these patterns. Target drilling of the mapped fractured zones by horizontal wells indicates a mapping accuracy of 30-50 meters. According to the logging, the zones of fracturing in the Jurassic and Cretaceous rocks are confined to the zones of carbonatization, and in connection with this, when the formation is fractured 2.3 times more it is likely to get «STOP». The accuracy and completeness of the fractured zones mapping using the OilRiver technology opens up the possibility of using filtration channels to improve the profitability of oil production.

**Keywords:** fractured-block structures, filtration channels, fractured-cavernous reservoir, horizontal wells, carbonatization, fracturing

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In case of reservoir models construction for Western Siberia, more attention is paid to the models lithofacial characteristics, which are considered as the main factor of reservoirs heterogeneity (Bastrikov et al., 2012; Volostnov et al., 2011). At the same time, based on the results of pressure transient testing (pressure buildup curves, tracer studies, well interference testing, etc.), it is established that to a large extent in the reservoirs under development there are out-of-model highly permeable elongated filtration channels formed by rocks fracturing.

In the early stages of oilfield development, this factor leads to uneven oil production, which does not attract much attention of reservoir managers. However, with the onset of waterflooding, premature high-speed breakthroughs of the injected water significantly complicate the generation of an oil displacement front, which ultimately leads to a decrease in oil recovery ratio. Moreover, according to the results of both indicator studies comprehensive analysis (about 20,000

measurements) and oil light absorption coefficient, in 23% of all measurements the speed of water movement in the Jurassic and Cretaceous reservoirs exceeds 150 m/day, which is accompanied by a sharp drop in the speed of oil movement (Sauley et al. 2010). In general, more than 40% of measurements indicate on pre-waterflooding and water breakthroughs associated with fracturing of rocks.

It is characteristic that the fracture filtration acts not as a scattered in space factor, but as concentrated narrow filtration channels with premature water breakthrough along them. Most often, formation of such channels is associated with the rupture of productive strata caused by water injection (Surovets et al., 2015; Shpurov et al., 1997).

Localization of fractures in narrow extended zones follows from incremental faults development regularities, where these faults act as zones of fracturing in the early stages of their development (Sherman, 1977). Platform faults are characterized by grid faulting stretching independently of both layers and folds strike in the folded basement of the platforms (Gzovskiy, 1975). Fracture modeling under conditions corresponding to the platforms sedimentary cover rocks deformations shows the formation of quadrangular block-fracturing systems

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(Fig. 1). At the same time, depending on the thickness of the deformable layer, the block sizes are stable despite the further increase in deformations (Revuzhenko, 2000). The modal nature of the block areas distribution in rocks follows the “equal areas” rule (Rats, 1970). Thus, based on the theoretical and experimental data, within the sedimentary cover of Western Siberia a regular block structure should be formed by two systems of faults.

Fracturing zones characteristics according to the results of target processing and interpretation of 3D seismic data

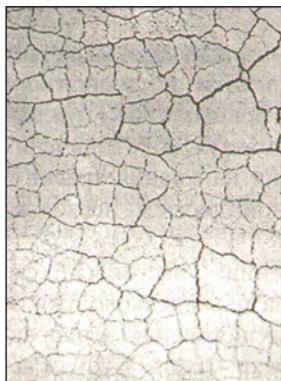


Fig. 1. Formation of a block structure under biaxial tension conditions (Revuzhenko, 2000)

Faults within the sedimentary cover of Western Siberia are at an early stage of their development and represent by 90-95% a set of extended fractures forming zones up to 100 meters wide. At this stage, as there is no any indicator proving the existence of an extended main seam, therefore there are no significant vertical displacements of the blocks along the faults, which prevents them from being identified in case of standard seismic data processing. Under these conditions, target processing and interpretation of seismic data within the framework of the OilRiver technology was developed and applied for stable mapping of the blocks displacements. The original feature of the technology

lies in the fact that the informative parameters of fractured zones are not the absolute values of the wave field characteristics, but the heterogeneity of its structure. Only in Western Siberia, the technology was implemented to study the block-fracturing structure for more than 40 active oilfields and exploration areas. An accumulated volume of exploration and geophysical data opens up the possibility of the following generalized characterization of both fractured zones themselves and block structures formed by them.

According to the results of fracture-block structures mapping based on the use of the “OilRiver” technology there was revealed the prevailing development of a single fractured zones generation consisting of two systems (Glukhmanchuk et al., 2016; Glukhmanchuk et al., 2014). As a result, quadrangular blocks with a close distribution of block areas (Fig. 2) dominate in the oilfields block structure. It is also characteristic that the size of the blocks (700-800 meters) is  $\frac{1}{2}$  of the sedimentary cover thickness for the Apt-Cenomanian time of tectonic deformation activation. This characteristic of block structures is due to the known geomechanical dependence of their size on the depth of the competent layer (in this case, the depth of crystalline basement). Rarely at the same time, two generations of faults may occur within some oilfields. The second generation is represented by arcuate elements curved towards the east. Their maximum development is identified within the uplifts. Elements of the northwestern and northeastern strike are less deformed, more extended and, as a rule, limited by sub-latitudinal elements (Fig. 3). Sub-latitudinal elements are much longer, with maximum intensity of suture characteristics, and therefore are often accompanied by secondary non-extended elements.

As a result of two faults generations participation in the formation of the block structure, the distribution of the block areas is changed significantly (Fig. 2). The increase in the number of blocks of the smallest area in

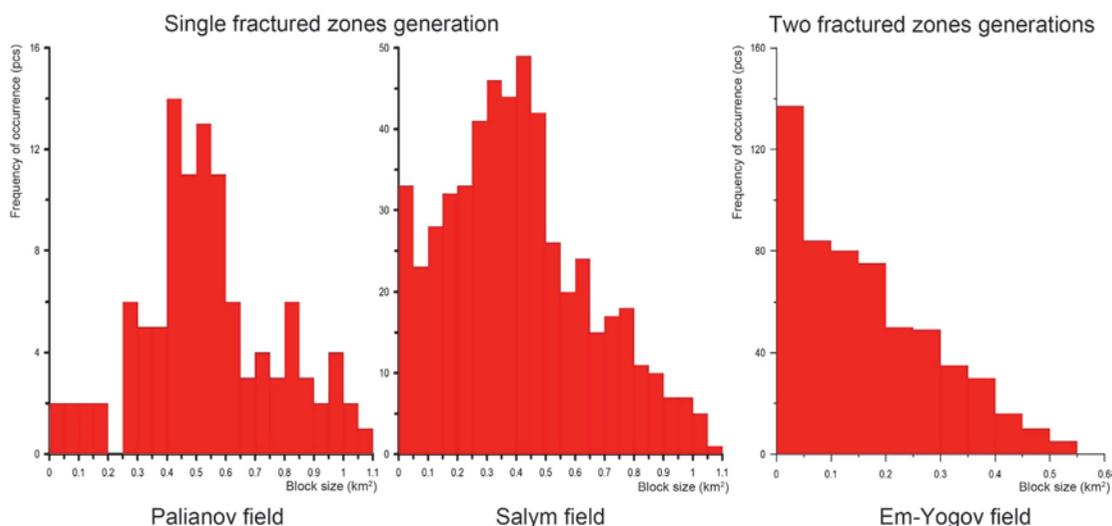


Fig. 2. Histograms of block area distribution

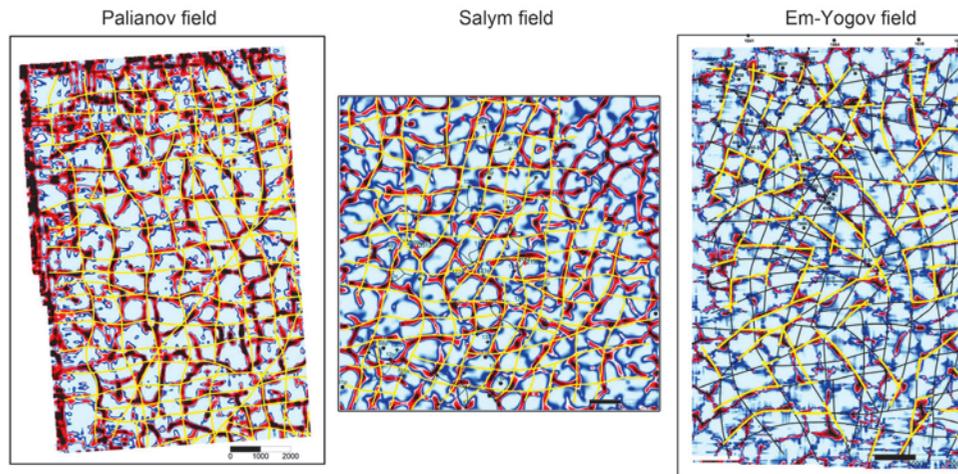


Fig. 3. The oilfield's block-fracturing structure and its relationship with wave field inhomogeneity structure

these conditions occurs due to formation of triangular shape blocks.

The presented figures show the fragmented intensity of fractured zones in the structure of the wave field inhomogeneity. Comparison with the well logging data showed that the maximum values of heterogeneity are confined to the most hydrothermally developed, as a rule, carbonatized fault nodes and areas of fracturing zones.

**Fracturing zones characteristics according to log interpretation in horizontal wells**

With such block sizes, a large part of horizontal wells with a length of a wellbore horizontal section up to 1 km crosses fracturing zones. As a result, the average specific indicator movement speed towards horizontal wells is 2.7 times higher than the indicator movement speed towards directional wells (Bakhtiyarov et al., 2007). Wells are studied by various well logging methods having different resolutions in terms of the fractured zones characterization. In this case, there were analyzed the results of standard logging, methods of high-frequency induction logging isoparametric sounding (VIKIZ) and FMI.

In Cretaceous porous reservoirs (AS layers) with high reservoir properties, fractured zones are characterized

by VIKIZ and gamma-ray logging (GR) as a part of porous reservoir including 4 carbonatization intervals within well section of up to 140 meters length (Fig. 4). Porous reservoir compaction occurs due to its secondary carbonatization, which, together with the presence of filtration channels, determines fractured zones as flow-diverting zones.

Two horizontal wells were drilled into the Upper Jurassic rocks (Yu<sub>0</sub> reservoir, Bazhenov formation) after conducting the fracture-block structure mapping within the oilfield (Fig. 5). The first, sub-latitudinal, was drilled directly along the fractured zone and crossed the fault node. Standard and gamma-ray logging in the well is characterized by extreme instability, which indicates the numerous intersections of the carbonate bodies by the well. This effect is most intense when the well trajectory completely coincides with the fractured zone in the fault node. When the well is located up to 50 meters from the fractured zone, the instability of the recording disappears and it acquires a standard form. From this, we can conclude that the width of the fractured zone in the rocks of the Bazhenov Formation is up to 50 meters.

The second horizontal well drilled sub-meridionally intersected two fracturing zones in perpendicular

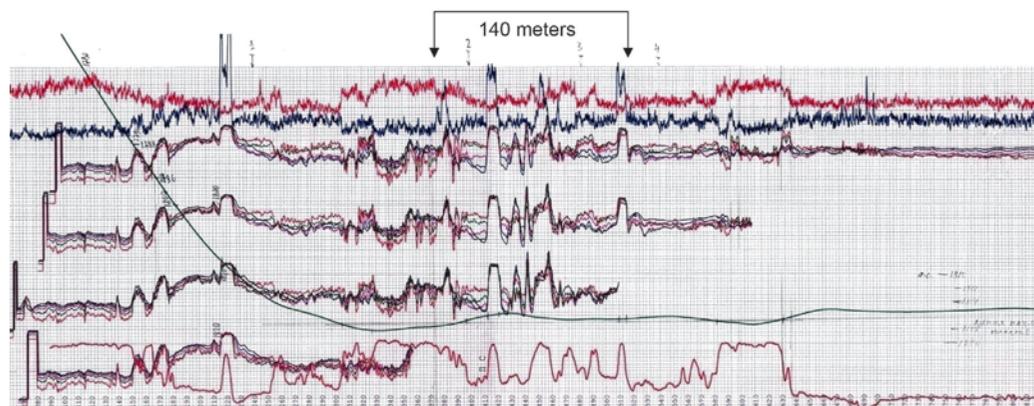


Fig. 4. Fracturing zones in Cretaceous sediments (AS reservoir) according to horizontal well logging data

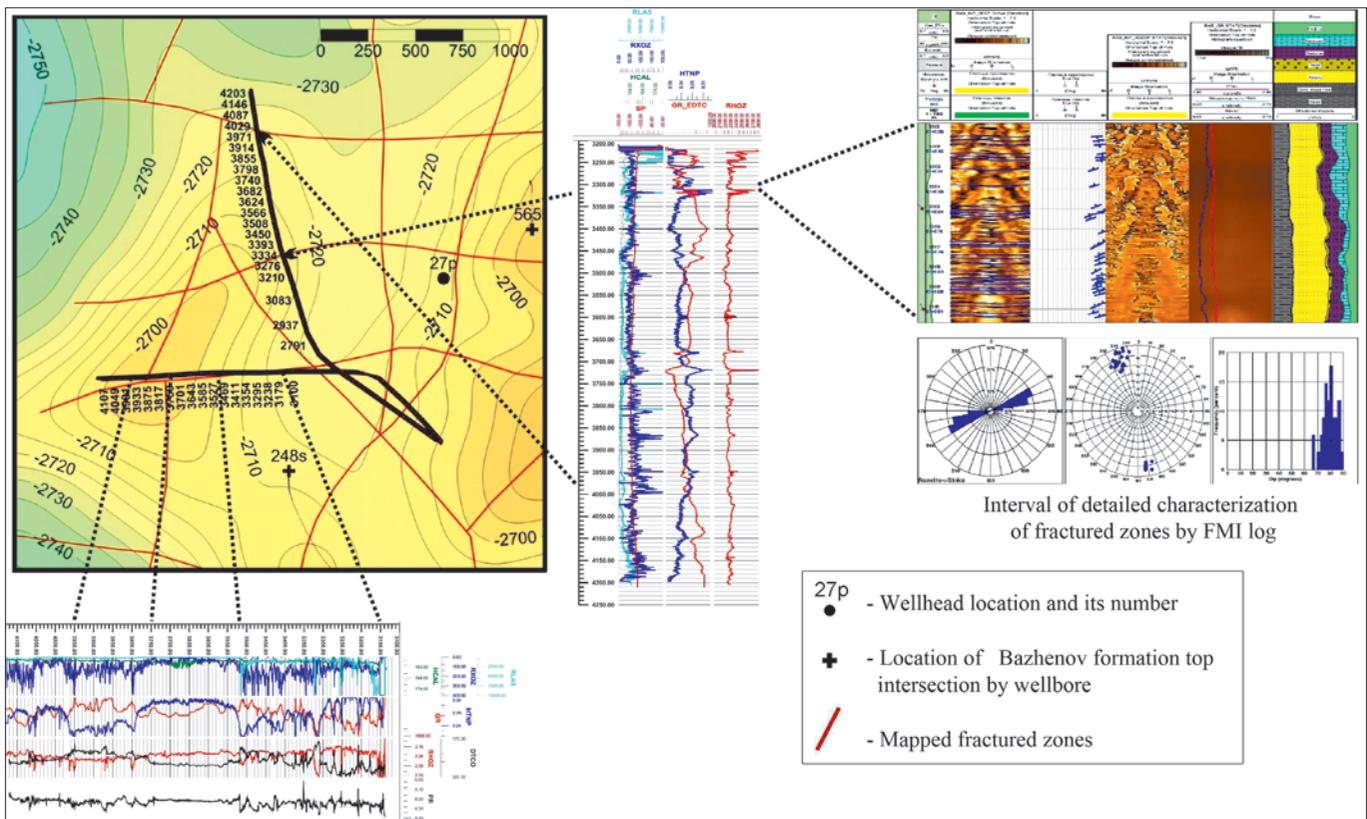


Fig. 5. Fracturing zones in the rocks of the Bazhenov formation according to horizontal well logging data

direction. In the standard logs, these zones are expressed as areas of rocks carbonatization having width of 1.5-2 meters (Fig. 5). According to FMI log, the fractured zone consist of up to 25 sub-vertical fractures, the strike and position of which completely coincides with the strike of the mapped fractured zone. The given examples characterize the fractured zones of Bazhenov formation as hydrothermally developed and

carbonatized areas mapped by using OilRiver technology with accuracy of tens of meters.

In case of horizontal wells drilling within previously mapped fractured zones, sub-perpendicular to the Tyumen Formation rocks, fractured zones are characterized by well logs (gamma-ray methods, acoustic and density logging) as intervals edged with vertical carbonate bodies (Fig. 6). At the same time, the most intensive

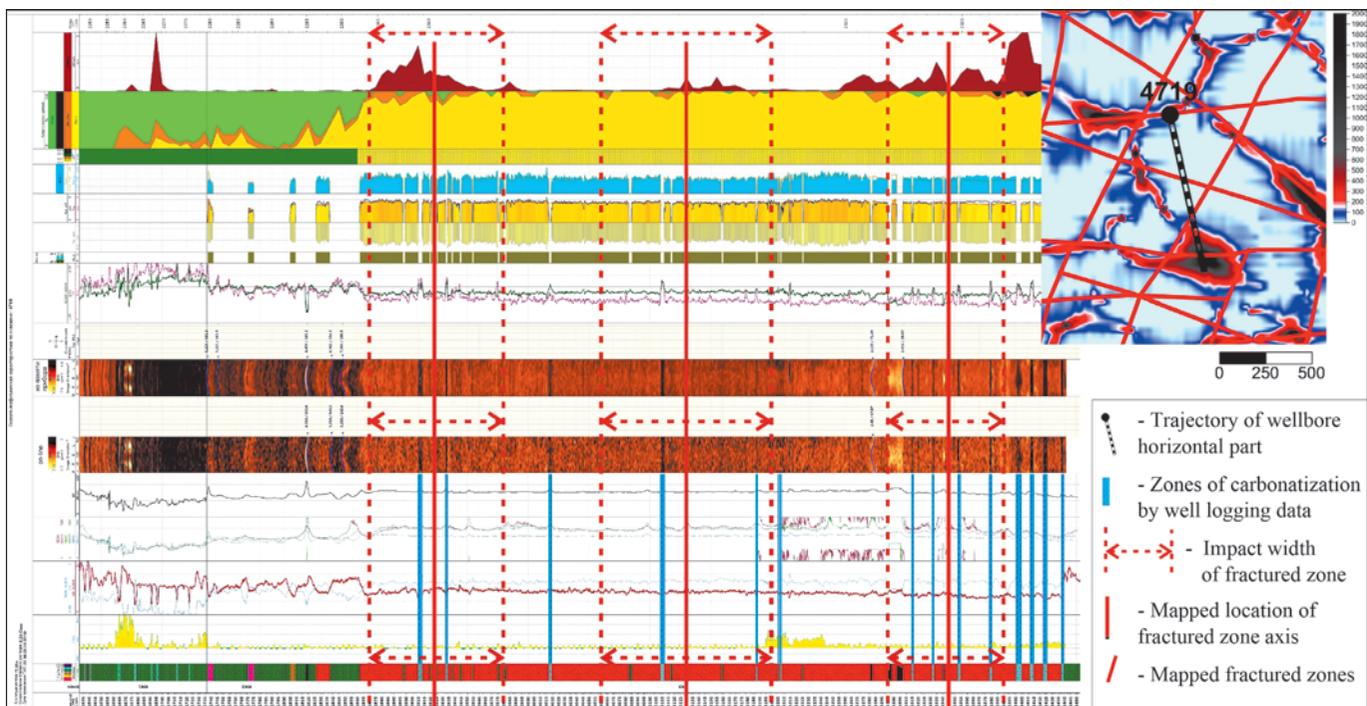


Fig. 6. Fracturing zones in the rocks of the Tyumen formation according to horizontal well logging data

carbonatization is observed in fragments of the zone with high wave field structure heterogeneity in the interval of the Tyumen Formation. It is also characteristic that gas anomalies are confined to the mapped fractured zones, indicating migration of light hydrocarbons into the reservoir.

Five drilling mud absorption intervals were observed in dense and even clay sediments of the Tyumen Formation while a horizontal well have been drilled along a fractured zone. Measured absorption intensity of 5-7 m<sup>3</sup>/h complicated the drilling of a well along the fractured zone indicating the presence of open fractures. Intense carbonatization of rocks (10 meters wide) in this well is observed in the fault node, to which, as before, is referred the wave field structure heterogeneity anomaly (marked on the map in red and black, Fig. 7). Thus, within the Tyumen formation, fractured zones are a combination of both open fractures and rocks carbonatization areas.

**Fracturing zones characteristics according to the results of hydraulic fracturing in horizontal wells**

Comparison of 153 hydraulic fracturing results in layers of the Tyumen Formation with mapped fractured zones showed that the chance of a screenout at hydraulic fracturing distance of 50 meters from the zones axes increased 2.3 times from 12 to 27%. At the same time, low (less than 90 atm) pressures of fracturing closure

at a distance of up to 100 meters from the zone axis are found 53% more often, which ensures maximum stability of flow rates. The average flow rate from one perforated (effective) meter within the reservoir in these wells is 1.5 times higher. In general, according to the results of hydraulic fracturing characteristics analysis in fractured areas, there should be noted the rocks consolidation (carbonatization) impeding the development of technogenic fractures.

**Conclusions**

A generation of fractured zones consisting of two systems forming quadrilateral blocks of similar sizes is predominant at the oilfields within the central part of Western Siberia. Triangular blocks are additionally formed in case of second generation occurrence causing both the decrease in block sizes as well as modality of their areas distribution deficiency.

Fractured zones in the Jurassic and Cretaceous rocks have a width of up to 100 meters and are characterized by both fractures and enclosing rocks partial carbonatization.

According to results of hydraulic fracturing, the chance of a screenout is increased in case of hydraulic fracturing within fractured zones of Tyumen formation, which means that the carbonatized parts of fractured zones are a hardened medium in which the formation of technogenic fractures is significantly difficult.

Technogenic fractures within the fractured zones

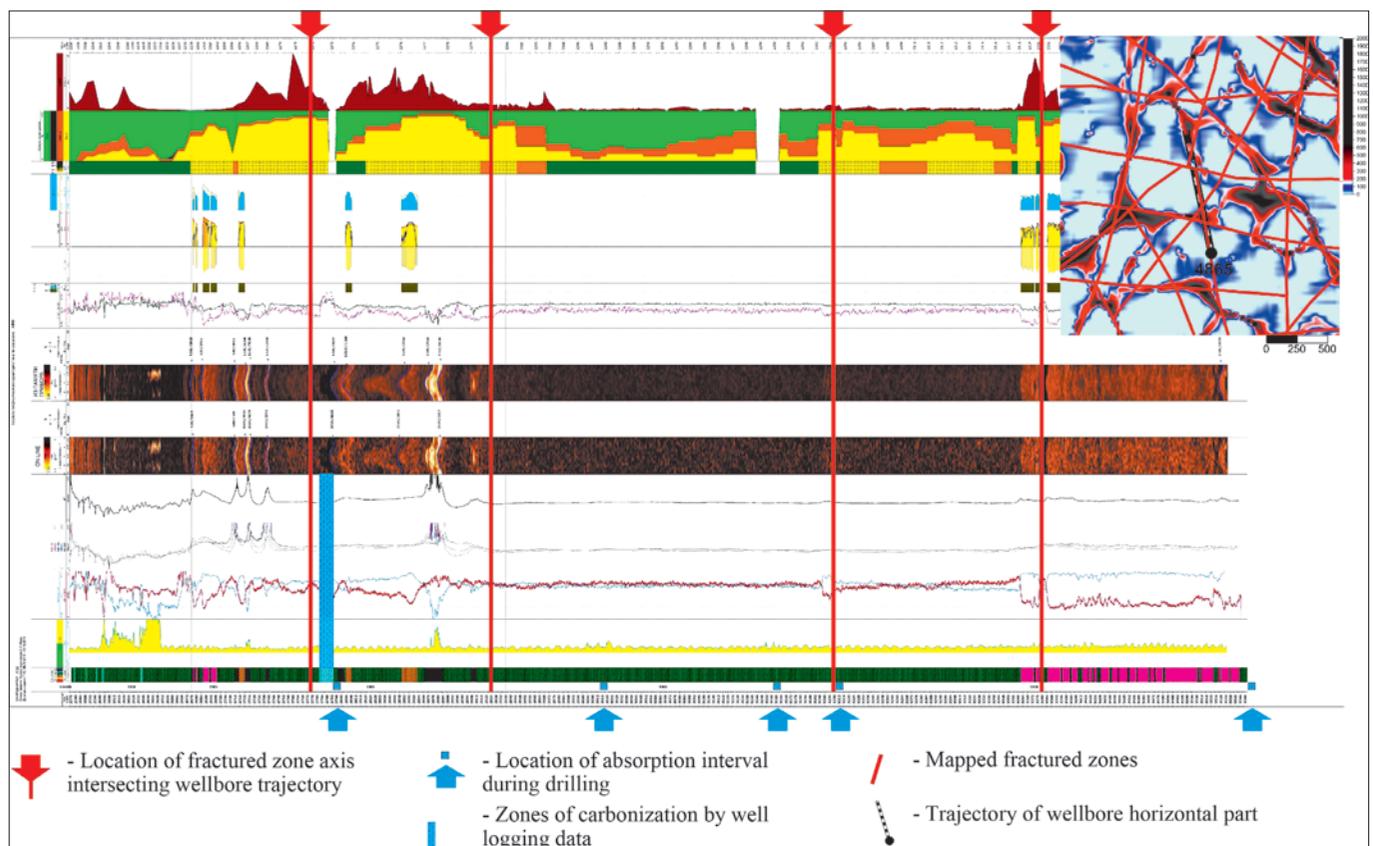


Fig. 7. Fracturing zones in the rocks of the Tyumen formation according to horizontal well logging data

are characterized by generally lower closure pressures, which provides a one and a half increase in average specific production rates. From this, it follows that the main reason for the decrease in the flow rates of technogenic fractures is their closure.

Comparison of horizontal wells drilling results with data on block-fracturing structures previously mapped by 3D seismic shows a discrepancy in matching of fractured zones of not more than 50 meters. Such accuracy along with the completeness of mapping creates a reliable basis for the effective hard-to-recover reserves development in case of fractured reservoirs as well as reliable background for reservoir pressure maintenance optimization by the placement of production and injection wells adapted in accordance with filtration channels location. According to the results of applying this principle when choosing the location of more than 30 producing wells in fractured cavernous reservoirs of the Bazhenov formation and the basement in a number of oilfields, was proven the possibility of cost-effective oil production for the most complex hard-to-recover reserves.

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# Method for constructing diffraction images of fractured-cavernous zones on the basis of multidimensional spectral filtration and new possibilities for studying the properties of geological media on the basis of multidimensional seismic data analysis of a common image point

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**Abstract.** The article describes the results of applying the original seismic data processing methods: Common Scattering Point Dip (CSPD) and Vector Pair Reverse Time Migration (VPRTM). Specific examples show that the CSPD method allows to effectively solve a wide range of tasks at various stages of geological exploration: search for fractured-cavernous zones, isolation of the cured faults, contouring of granite intrusion, identification of hazardous drilling zones and geonavigation of horizontal drilling. The VPRTM method is effective not only for detecting weak diffractors but also promising for simultaneous accurate analysis in various procedures.

**Keywords:** processing, scattered waves, diffractors, vector pairs, fracturing

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Fractured reservoirs contain more than a half of the world's hydrocarbon resources, and a significant amount of hydrocarbons is situated in low-porosity Carbonate rocks. Reservoirs in such rocks are mainly confined to fracture zones, for which the main source are tectonic faults. Very often it is the disjunctive faults through which hydrocarbons migrate to traps, and accumulate there. Due to good reservoir properties, such zones provide high flow rates in wells. Fracture tectonics determines the structure, level of capacitance characteristics and saturation of the fracture space. Deposits in the fracture-type reservoirs are referred to complex ones. Effectiveness of prospecting operations in such deposits applying conventional methods is much smaller than in regular porous reservoirs. Russia actively develops a seismic exploration trend aiming at identification of increased fracturing zones over scattered seismic waves. Transnational oilfield servicing companies are also active in Research & Development on the issues related to application of scattered waves.

The limitations of an original pre-stack multi-channel processing method applied by us – Common Scattering Point Dip (CSPD) – are defined due to a high quality division of the full wave field into reflected and scattered components and the quality of data to be processed. The method was tested on synthetic and field data and proved its efficiency. Verification of the method included processing of more than 20 thousand line kilometers of seismic lines and over 6 thousand sq.km of 3D seismic data at 50 fields. The survey areas are situated in many oil and gas-bearing provinces of the world and in various geologic environments. These include West Siberia, Lena-Tunguska and Volga-Urals oil and gas provinces, as well as some survey areas and seismic lines in Poland, Kazakhstan, China, the Barents Sea, Brazilian and Antarctic offshore areas. The following geologic targets were surveyed by the CSPD method:

- fracture reservoirs in clay rocks of Bazhenov and Abalaksy suites;
- pre-Jurassic complex in West Siberia: fracture-cavernous reservoirs in Triassic magmatic rocks, Devonian Carbonate rocks, basement's weathering crust;
- Cambrian Carbonate and Vendian-Riphean deposits in East Siberia;
- Devonian reefs in Volga-Urals Oil & Gas Province;

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- Carbonate, volcano-genetic rocks, magmatic rocks of Pre-Caspian Province;
- volcano-genetic Terrigenous Triassic rocks (China, Latin America).

Let us illustrate the link between scattering index generated by CSPD method, and reservoir's productivity in horizontal wells, by comparing Mud Logging data acquired while drilling horizontal wells with scattered waves (diffractors) amplitudes in a borehole zone within the boundaries of a productive horizon.

Mud Logging data is used to identify within a well section intervals with oil and gas potential, and to evaluate formations' saturation type. In order to interpret Mud Logging data (TG), it is necessary to have information concerning some technological parameters of the drilling process. Therefore, along with Mud Logging, they conduct Mechanical Logging – recording the rate of penetration (ROP). One of the parameters affecting the drilling speed is fracturing. Information on its presence can be obtained from scattered waves interpretation data. Taking these zones into consideration will allow to adjust planned well path before start of drilling, and to avoid complications and accidents during drilling (Anokhina, Zhegalina et al., 2017). Data selection represents amplitudes of scattered waves on the horizontal part of wells, recorded right along the wellbore and in bottomhole zone where values have been summarized in volumes with 25 m, 75 m, 125 m, 175 m diameters (so called «pipes»).

Available data was used to generate average values curves TG/ROP from average diffractor values. For each row of data, a trend line and data approximation reliability value ( $R^2$ ) were loaded (Fig. 1). All ( $R^2$ ) values from all generated curves were entered in Tables and this data was used to generate a curve showing the relation between  $R^2$  and averaging diameter (Fig. 2). Along the horizontal axis is the “pipe” diameter, along the vertical axis are  $R^2$  values.

The physical reason is in an attempt to find a “feeding zone” of the wellbore's horizontal part. As seen on the plot (Fig. 2),  $R^2$  values gradually grow along the increase

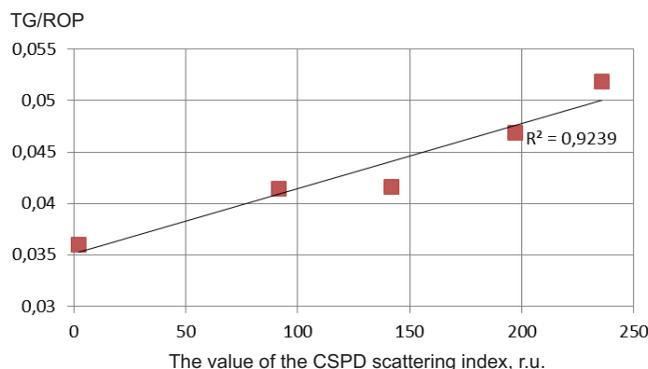


Fig. 1. Relation between average TG/ROP values and average diffractor values within 125 m diameter from the wellbore

in diameter of the “pipe” from which average diffractor values were derived, then reach maximum for 75-125 m diameter pipes, and begin to decline.

This means that main abnormal scattered waves values, whose appearance we associate with presence of a fractured reservoir, are situated in this zone. Considering this, we can assume that the well takes the largest amount of its extracted product from the 150 m diameter zone. But during drilling horizontal holes, the Mud Logging and ROP readings are affected by not only physical properties of the rocks (first of all, porosity and fracturing) and their lithology, but by well drilling technology as well. An attempt to link changes in TG and ROP values only with technological or only with geological matters may lead to erroneous interpretation of Mechanical Logging data.

Involvement of additional information in the form of scattered waves interpretation data, which identify fracture zone, allows to reduce uncertainty connected with a geological factor. This data plays an extremely important role during well designing and selection of its configuration, and make it possible to conduct drilling activities in optimum technological mode, avoiding emergencies (Erokhin et al., 2016).

Tasks accomplished by CSPD:

- search for fractured-cavernous reservoirs;
- outlining the granitic intrusion;
- identification of healed faults and faults with open fracturing;
- identification of areas dangerous for drilling activities;
- geo-steering of horizontal drilling.

Let us see a few examples of searching for fractured-porous reservoirs. Prediction of spreading zones of fractured and cavernous reservoirs by scattered waves is based on the following principles:

- scattered seismic waves with high amplitudes form in the zones with a significant concentration of open fractures and caverns filled with fluid. The less open fractures and caverns are in the rocks, the lower are amplitudes of the scattered waves field.

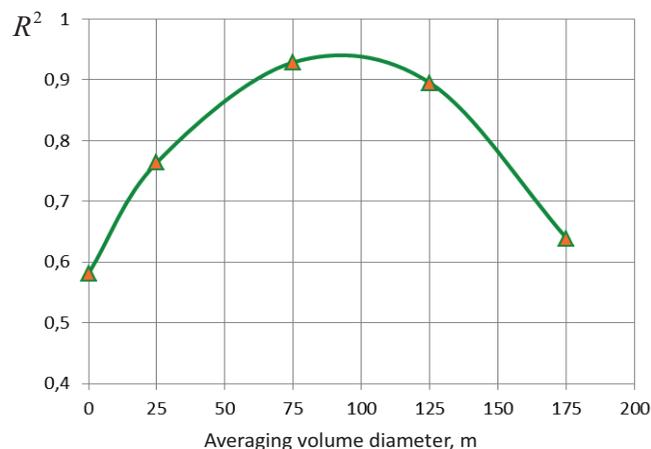


Fig. 2. Relation between average TG/ROP values and averaging volume diameter

- saturation of fractures has very little effect on scattered waves amplitudes, therefore there is no possibility to establish type of fluid which fills the fractures.

- porous reservoirs have low scattered waves amplitudes, almost close to background values. That's why when there are porous and fractured reservoirs in the surveyed productive interval, the scattered waves sections and maps only show increased fracturing zones but not porosity.

At the initial stage of interpretation, taking into account drilling materials, they identify intervals where complications are associated with fracturing zones. Further they establish a match between presence of fracture zones in a well and emergence of amplitude anomalies on scattered waves sections and maps. Then such places are examined in other parts of the area, and a prediction is provided for spreading of zones interpreted as zones with fracturing.

Fig. 3 shows sections with reflected (left) and scattered (right) waves acquired after specialized processing at a field in West Siberia. The reflected wave section does not enable any assumption on presence of fracture zones. By involving a scattered component of the wavefield, it is possible to unambiguously show the places which due to penetration of a fractured reservoir would ensure high flow rates in wells. On this and following Figures, blue color means low scattered waves amplitudes and absence of fracturing and cavernosity, whereas red and yellow correspond to high amplitudes relating to fracture and cavern zones.

We will substantiate the forecast made for drilling

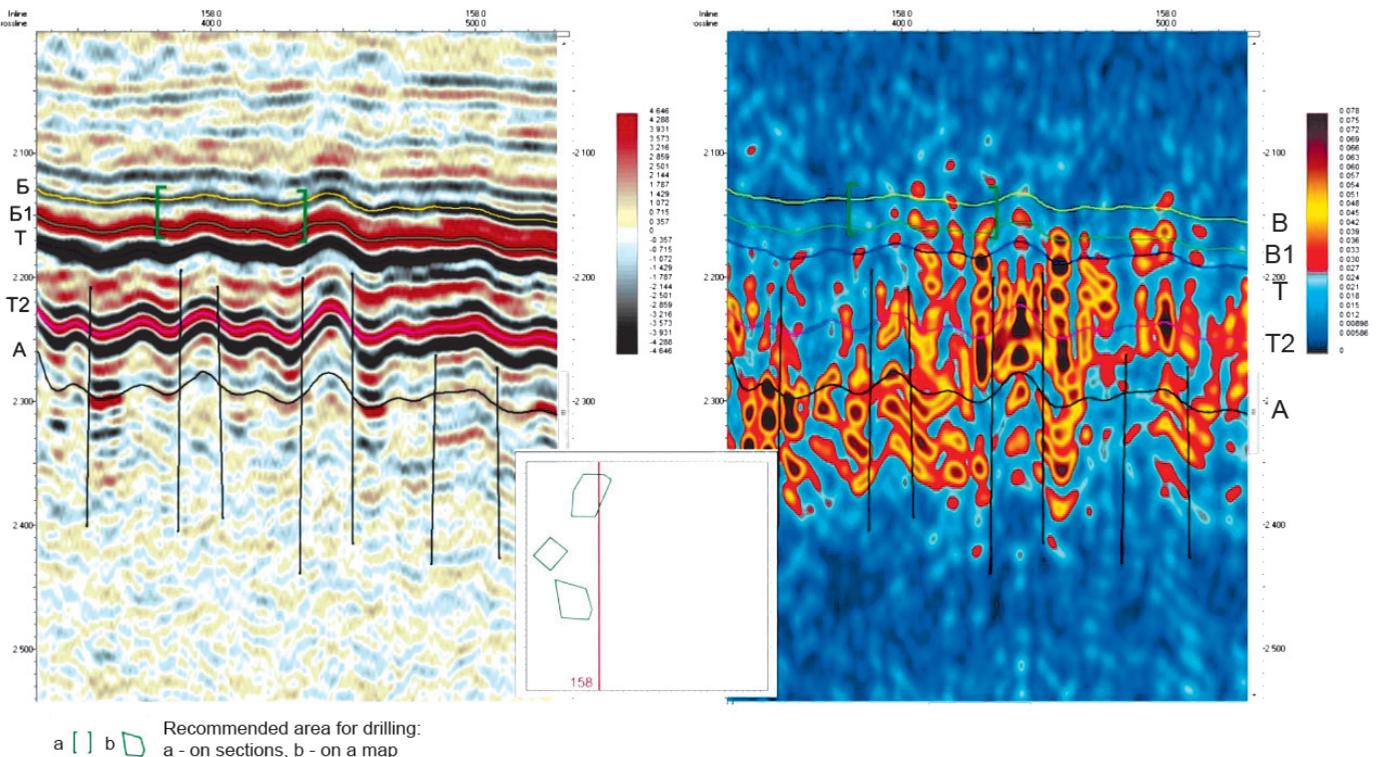


Fig. 3. Sections of reflected and scattered waves acquired after specialized data processing

according to CSPD method with a case study of an oilfield in Kazakhstan. The main oil-bearing target is Mid Triassic deposits in which two members are identified: volcanogenetic-dolomitic and volcanogenetic-limestone, they are associated with productive horizons T2b and T2a, respectively. Reservoirs in both members are complex, fracture-cavernous and porous-cavernous, they spread along the area in a mosaic pattern and do not conform to structural factor (Kirichek et al., 2013).

In order to forecast zones of fracture-cavernous reservoirs in Triassic deposits, we generated and analyzed maps containing scattered waves amplitudes in the time intervals which correspond to productive horizons (Fig. 4).

After completion of works, well No. 15 was drilled at the field which penetrated identified bed with a fractured

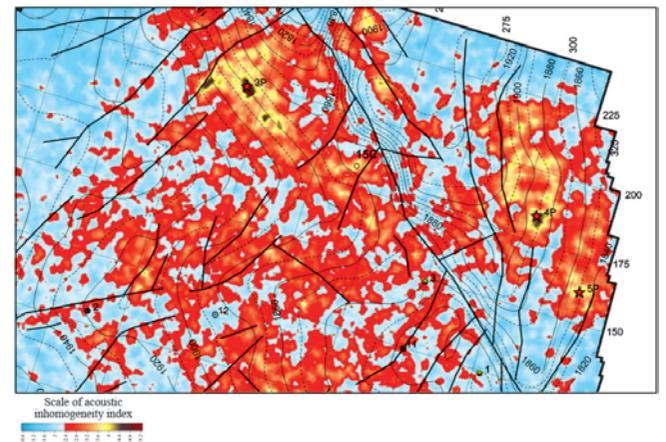


Fig. 4. Map of cumulative scattered waves amplitudes for horizon T2b

reservoir in productive horizons: oil flow amounted to 124 m<sup>3</sup>/day (Fig. 5).

Verification of this forecast which is based on scattered waves acquired with CSPD technology makes it possible to recommend this technology for mapping non-conventional complex reservoirs of fractured type.

### Outlining the granitic intrusion

Target of the survey is Oimasha field in Kazakhstan. The main oil-bearing capacity is associated with Mid Triassic deposits and granitic intrusion.

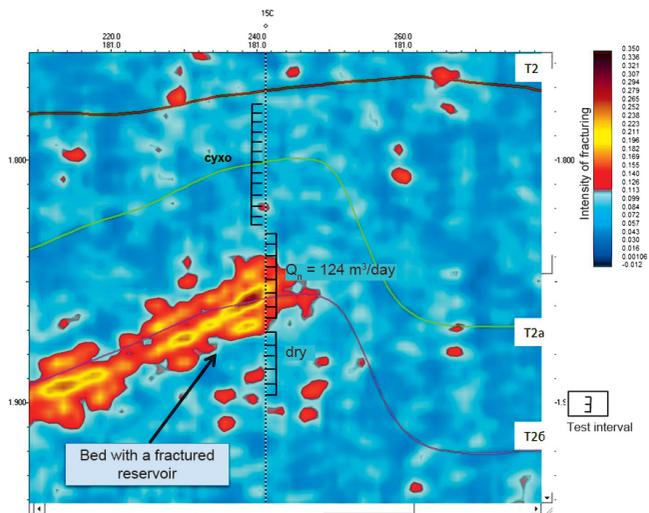


Fig. 5. Time section of scattered waves through well 15

Within the granitic intrusion, oil saturation is in the uplifted part of the granitic mass which cropped out on the day surface where weathered granites mainly developed. These weathered granites were situated at different depths from the surface of the granitic mass which was confirmed by testing and well drilling. Reservoirs are characterized by high heterogeneity and variability over the area and the section, therefore the formation reservoir has complex outlines.

This field was selected as a testing ground for comprehensive studies of the subsurface applying geological and geophysical methods. Detailed seismic exploration, high-precision gravity and magnetic surveys were carried out, but despite such a large scope of works completed, data on the structure of the reservoir within granitic intrusion was not acquired. Only a promising block was identified in the north-eastern part of the granitic intrusion. So it was decided to apply the CSPD method based on scattered waves.

Due to this method it was possible to not only map the top of granitic intrusion not visible on reflected waves (Fig. 6), but also, after interpretation, to identify zones with various potential in the granitic intrusion occurrence interval with fracture-cavernous type of the reservoir, which contains an oil accumulation.

By analyzing how intensity of scattered waves field changes along the section (Fig. 7), within the granitic intrusion interval it is necessary to point out that the

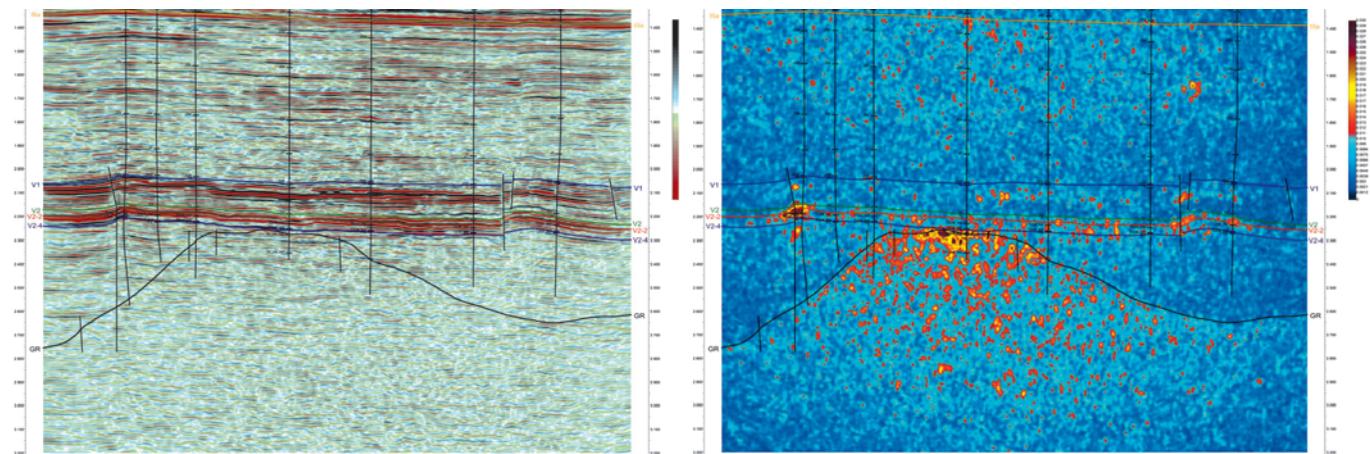


Fig. 6. Sections of reflected and scattered waves acquired after specialized data processing

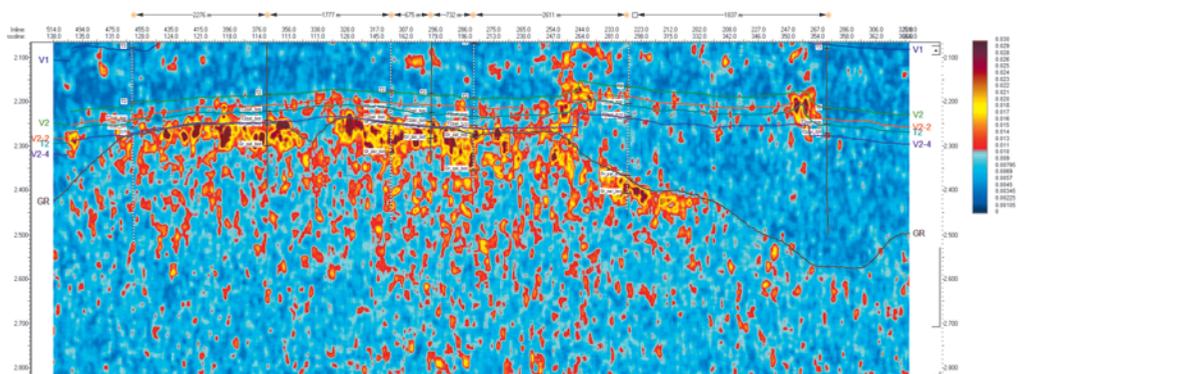


Fig. 7. Time section of scattered waves through wells. Identification of healed faults and faults with open fracturing

field’s intensity falls abruptly along with depth which may indicate deterioration of reservoir properties. All drilling data, well testing results and core studies indicate that interval of rocks with good reservoir properties was not more than 100-150 meters (Anokhina et al., 2014).

**Identification of healed faults and faults with open fracturing**

Faults represent main sources of fracturing, therefore it is crucially important to generate a complete picture of fault tectonics for the surveyed field. It can be acquired by joint interpretation of reflectors cube, diffractors cube and instantaneous and geometrical attributes cube. Deep faults and expansion zones form conductive channels – the ways for hydrocarbons to migrate and enter previously formed traps (Anokhina, Demidova et al., 2017). Appearance of faults in the scattered waves field is associated with fracture zones confined to such areas. Separation of the faults into conductive and healed ones is an important task which is quite hard to solve according to reflected waves without involving the scattered components.

Specialized processing of seismic exploration data was carried out at Yuxi field in the north-east of China. Results of this work allowed to separate mapped faults into permeable and healed ones (Fig. 8). On the section of reflected waves (Fig. 8, left) it is impossible to understand which faults will be conductive. And only by involving the scattered component (Fig. 8, left), we can see that faults in the western part of the field are healed (Fig. 9), and good flow rates should not be expected in wells there.

Since faults are the main sources of fracturing, it is crucially important to generate a complete picture of fault tectonics for the surveyed field, which can be acquired by joint interpretation of reflectors cube and diffractors cube. In addition, such interpretation allows to separate the faults into fluid-permeable and non-permeable. There also appears a chance to map permeable faults without vertical shifts, identification of which on reflected waves sections causes much doubt.

**Identification of zones dangerous for drilling**

Let us examine a case of similar operations conducted at a field in the eastern part of Angara-Lena oil and gas-bearing area of Lena-Tunguska Oil & Gas Province.

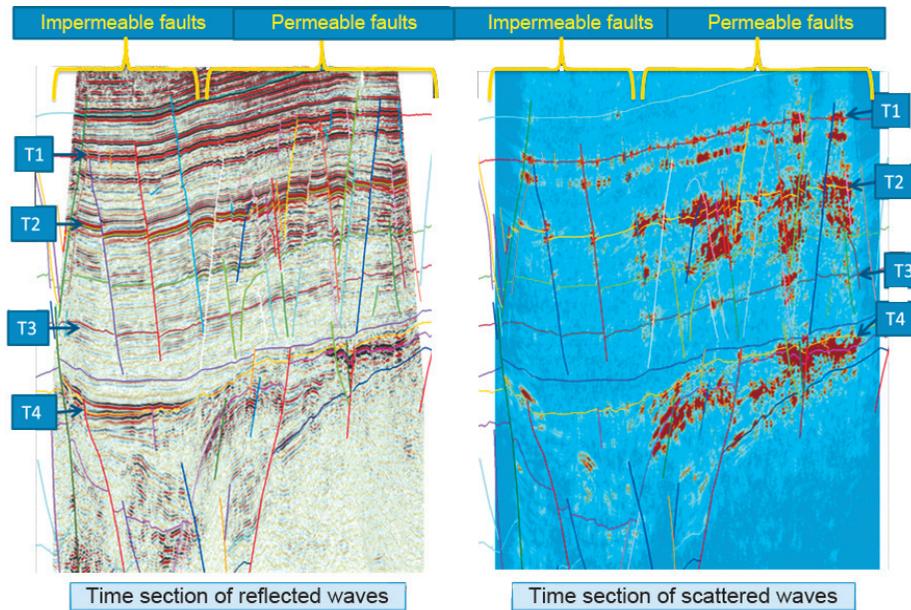


Fig. 8. Sections of reflected and scattered waves acquired after specialized data processing

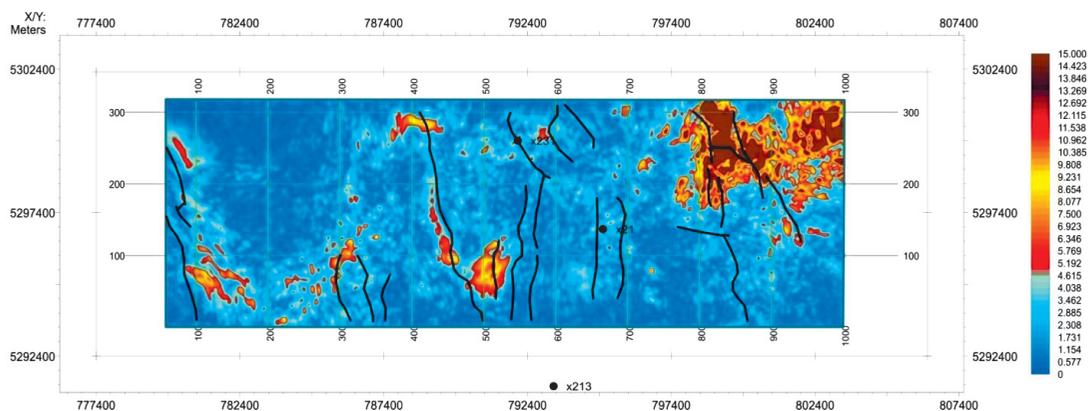


Fig. 9. Map of cumulative scattered waves amplitudes for horizon T3

Main potential oil and gas-bearing objects in this region are sandy horizons within pre-salt Terrigenous sequence. Previous exploration in the surveyed region shows that drilling of prospecting and exploratory wells in thick salt beds above oil and gas accumulations is often complicated and even becomes impossible due to natural brine shows.

Five deep wells have been drilled in the survey area. Drilling of wells A and B was suspended in the upper part of Usolye suite in Lower Cambrian deposits. The wells were abandoned due to an accident associated with salt brine (rapa) inflow in Christophorov and Balykhtin horizons. Complications during drilling also occurred in overlying intervals of the geologic section (Bilchirsky horizon) in wells D and A. Wells D, F and G penetrated a productive interval of Vendian deposits at more than 2000 m depth.

The interpretation process for the entire survey area included correlation and connection of key reflector horizons. Their connection was conducted as per Vertical Seismic Profiling and Logging data acquired in wells located in the survey area and in direct proximity (Fig. 10).

Forecast over scattered waves in the zones which may present hazards during drilling due to presence of fracturing and emergence of various complications associated with presence of areas with abnormal high formation pressure, is based on the same principles as forecast for reservoirs of fractured and cavernous types.

An example is a resultant map containing total amplitudes of scattered waves in the Bilchirsky horizon which overlaps a productive interval (Fig. 11). The map shows the wells in which salt brine or gas shows were encountered caused by abnormally high formation pressure. Scattered waves' amplitude anomalies singled out on the map may be identified with spreading of fractured-cavernous reservoir in dolomites. Filling of the reservoir may vary: either formation water with high salinity (rapa) or hydrocarbons. For example, gas shows were encountered in well A in Bilchirsky horizon. Identified zones are likely to have abnormally high formation pressure.

Near well G the scattered waves anomaly is much smaller, and passing through this interval during drilling in this well did not cause any difficulties.

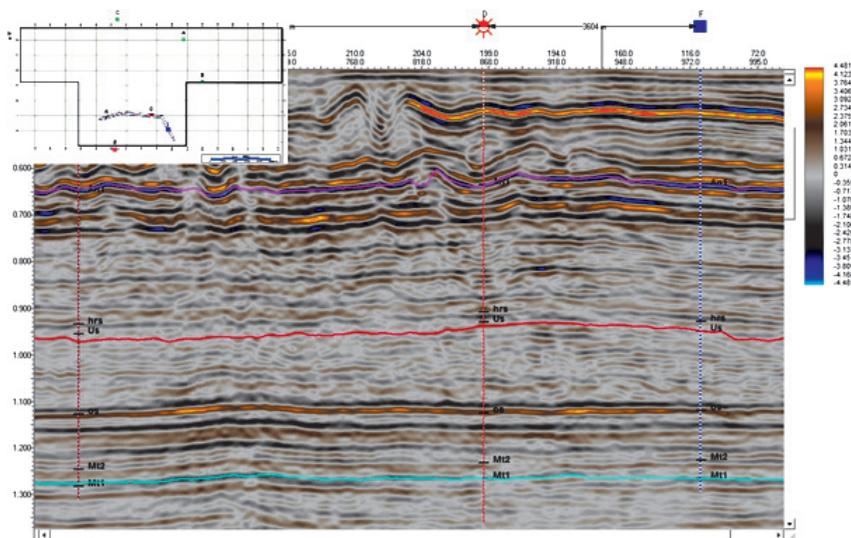


Fig. 10. Vertical slice of reflected wave cube passing through wells D, G and F

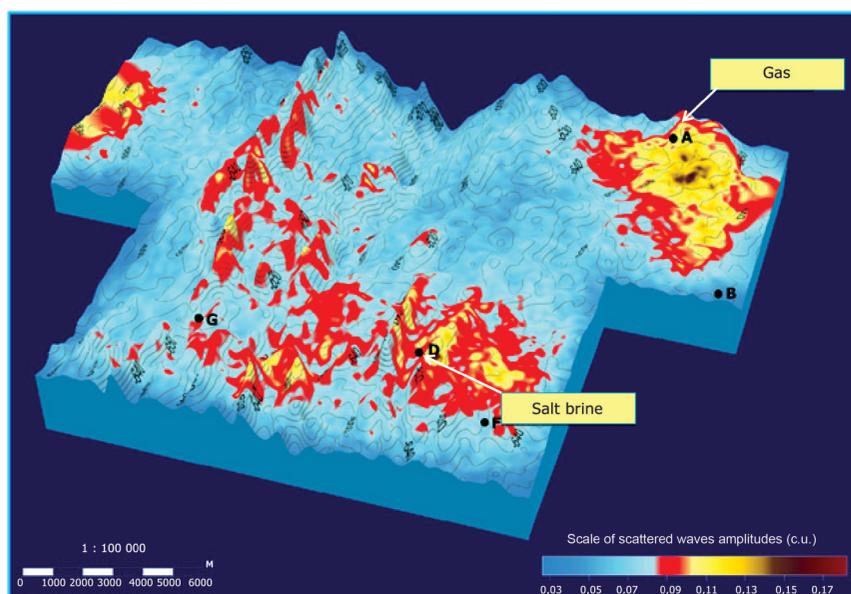


Fig. 11. Map of cumulative scattered waves amplitudes for Bilchirsky horizon

So, seismic surveys with scattered waves allowed to identify rather vast fracturing zones in the survey area associated with abnormally high formation pressure, as well as with areas of splitting along faults, which present interest during designing and selection of a technology for deep drilling.

Interpretation resulted in a map showing fracture zones in Lower Cambrian deposits (Fig. 12). Application of specialized processing which separates the full wavefield into reflected and scattered components, allows to identify fracture zones, in particular in intra-salt formations of Lower Cambrian dolomites filled with high-salinity formation waters.

Special value of using the scattered waves' component is in the forecast of abnormally high formation pressure before start of drilling. Such data is extremely important during designing of the well and selection of its configuration. It enables to conduct drilling in an optimum technological mode avoiding emergencies (Anokhina et al., 2016).

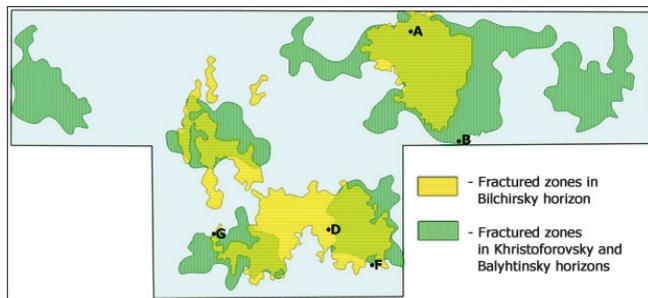


Fig. 12. Predictive map for fracturing zones in Lower Cambrian deposits

### Horizontal drilling geo-steering

In recent times, a question often arises concerning the need to develop fields with fractured type of reservoir confined to Carbonate deposits, followed by drilling of horizontal holes. Therefore correct identification of fracture zones is a very important task because these very zones are confined to tectonic

faults which provide good reservoir properties and consequently high flow rates. In order to identify such zones, in addition to establishment of kinematic and dynamic characteristics of reflected waves, it is necessary to involve completely new technologies and forecasting techniques, such as:

- scattered waves which allow to identify intervals with increased fracturing and cavernosity of productive formations, destruction zones and other objects (the CSPD method);

- micro-seismic monitoring data which enables to identify peculiarities of the reservoir which contains hydrocarbon deposits (the MSPRM method).

Both methods accomplish the task of mapping the open fracturing zones.

Let us study an example of a field with regionally oil and gas-bearing Upper Jurassic sub-sequence (Bazhenov – Upper Abalaksy). Reservoirs in formations IO<sub>1</sub> (Upper Abalaksy sub-suite) and IO<sub>0</sub> (Bazhenov – Lower Tutlemeisky sub-suite) have a rather complicated development character caused by both micro-lamination and foliation of rocks, as well as by tectonically stressed zones (disjunctive fault zones, destruction, stretching and compression zones) and hydro-thermal processes (desalination and dissolution). Type of the reservoirs is porous/cavernous/fractured.

A 3D survey was conducted in the area which was processed according to CSPD method, followed by multistage hydraulic fracturing along with micro-seismic monitoring. This allowed to conduct comprehensive interpretation of already available scattered waves cubes and new micro-seismic data.

Multistage hydraulic fracturing was carried out in the horizontal hole accompanied by micro-seismic monitoring. According to well tests, the last three ports yielded oil inflow. On the scattered wave section they fall into the zone of higher values, which indicates presence of fracturing. Main micro-seismic events recorded during hydraulic fracturing are also localized near these ports (Fig. 13).

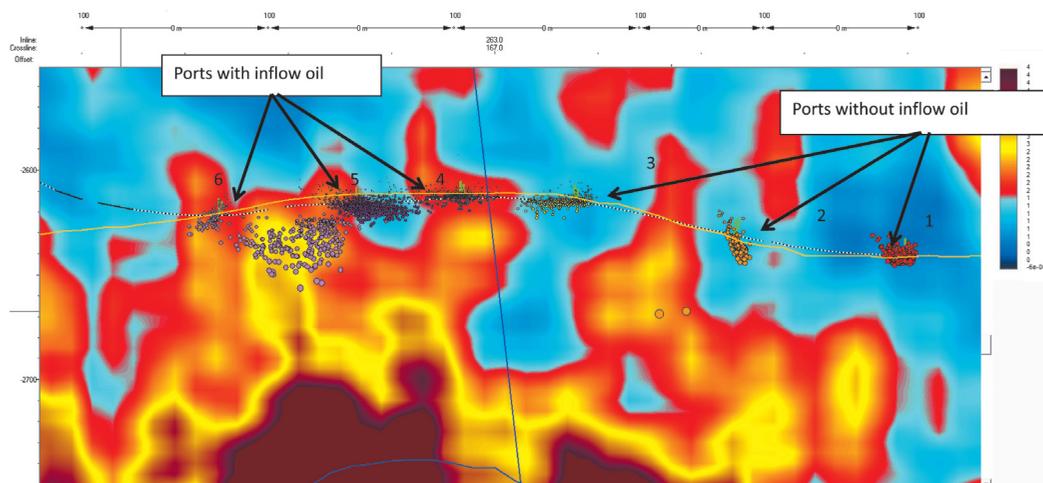


Fig. 13. Fragment of a time section for scattered waves cube projecting the micro-seismic events cloud

Specialized processing of seismic data according to CSPD technology allows to identify areas with natural open fracturing and zone with “unhealed” faults. Micro-seismic emission emerges in the zones of “currently-living” faults and in the areas with open natural fracturing. Such zones are encountered during passive micro-seismic monitoring applying the MSPRM technique. Joint interpretation of data integrated from these methods allows to reliably forecast the location of zones with open fractures and draining in space, since anomalies of scattered waves field with high amplitudes and cloud of micro-seismic events have the same nature. Management of formation stimulation results during hydraulic fracturing allows to acquire data on the directions of fracking areas development during acid fracturing near the development of a productive formation, and thus to upgrade the field development system and to increase forecasting accuracy for reservoir spreading zones confined to fracturing zones, and efficiency of prospecting drilling (Anokhina et al., 2016).

In addition to the CSPD and MSPRM technologies, Research Institute of Applied Informatics and Mathematical Geophysics of Immanuel Kant Baltic Federal University has elaborated and implements a new approach to medium visualization, based on application of inter-dependent visualization of paired images (IVP IC). The method based on such approach is called Vector Pair Reverse Time Migration (VPRTM).

The state of image processing is a key factor for the RTM method. Conventional RTM-images have original artefacts because this method is based on wave equation. In order to overcome such obstacles, image

regularization is accomplished on the basis of seismic data filtering in an extended domain of image common point parameters (Vector Dimension Common Image Gather).

The present paper provides the VPRTM development results, in particular, using an example of finding ultra-weak diffractors against strong reflections on a field in West Siberia. Reflection or scattering of acoustic wave on an obstacle at any time may be seen as interaction of two inter-connected vectors: incident wave particle velocity vector and reflected or scattered wave generation vector. We suggested an accurate statistical analysis of amplitudes and phases of inter-connected vectors for all time samples and sources, and elaborated the conditions for imaging the inter-connected vector pairs, which allows a new outlook on visualization of acoustic media (Erokhin et al., 2017). Fig. 14 shows an example of reflected waves section, with a “smile” object singled out.

Solutions to a direct and associated challenge are based on first-order equations. This allows to work at each point of space in the first arrivals zone with pairs of inter-connected vectors which depend on time and sources. Filtering of inter-connected vector pairs in amplitude and phase domains establishes a tolerable set of pairs. Application of this set of vector pairs allows to generate images of the medium which are more descriptive than conventional RTM images (Fig. 15).

It is clearly visible on the time section for reflected waves MULTI BackRTM that traceability of reflectors improves significantly despite a loss of high frequencies in the section. In case of scattered waves we can

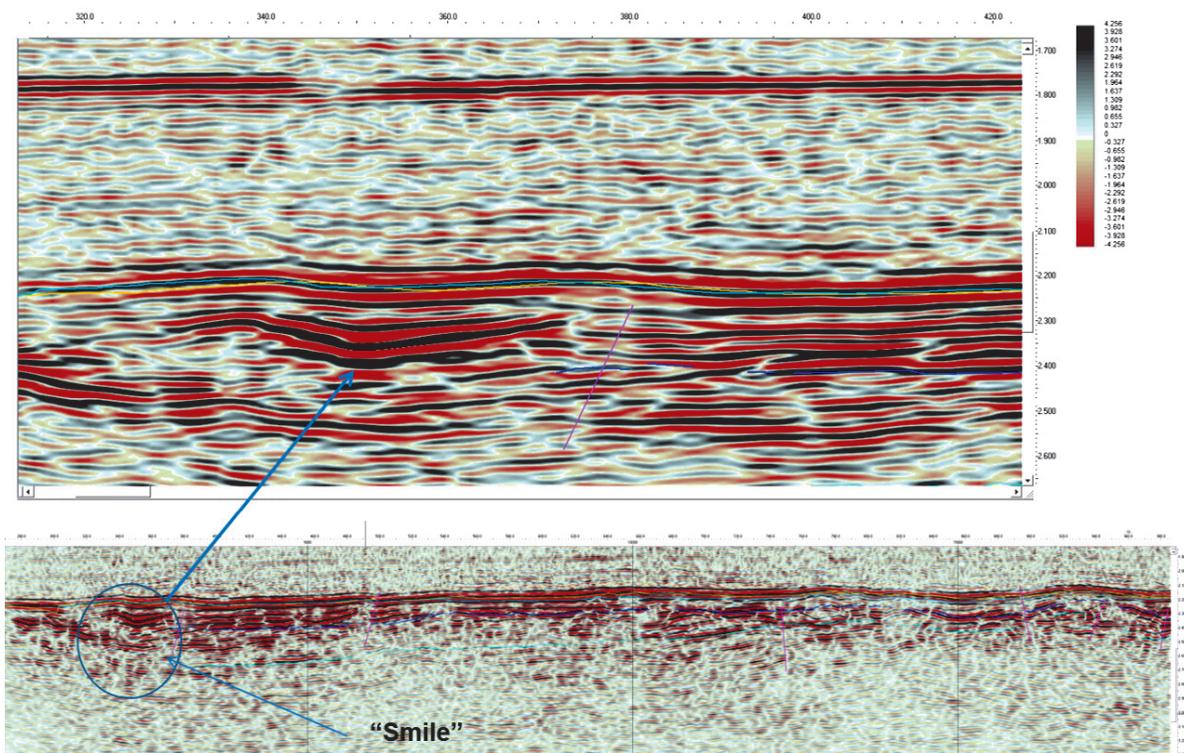


Fig. 14. Vertical slice of reflected waves cube with “Smile” object singled out

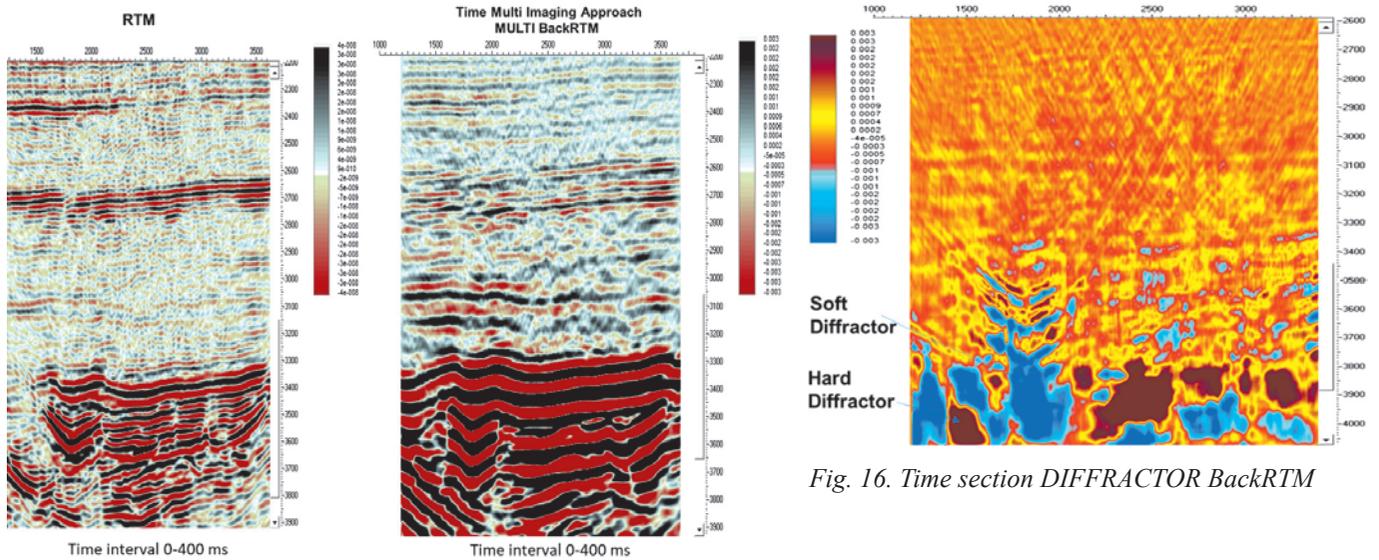


Fig. 15. Example of time sections RTM and MULTI BackRTM

differentiate decompaction zones – soft diffractor, and compaction zones – hard diffractor (Fig. 16).

The VPRTM method with background diffraction demonstrates high sensitivity to velocity fluctuations. The method has a potential for analysis in AVO, Dip, Frequency, Impedance, Reflectivity and Diffractivity procedures.

Figures 17-19 show examples of VPRTM sections: attributes Impedance, DIP and Fluid Factor.

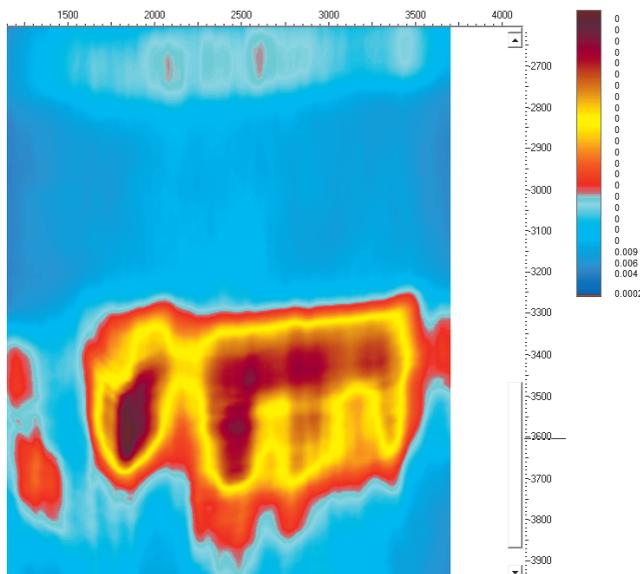


Fig. 17. VPRTM: Impedance

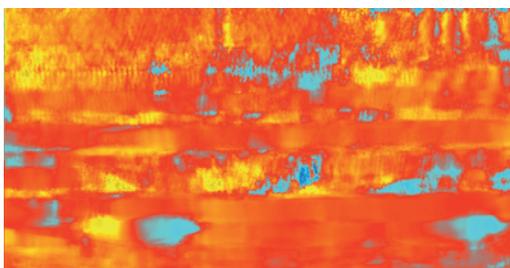


Fig. 18. VPRTM: DIP+25OC

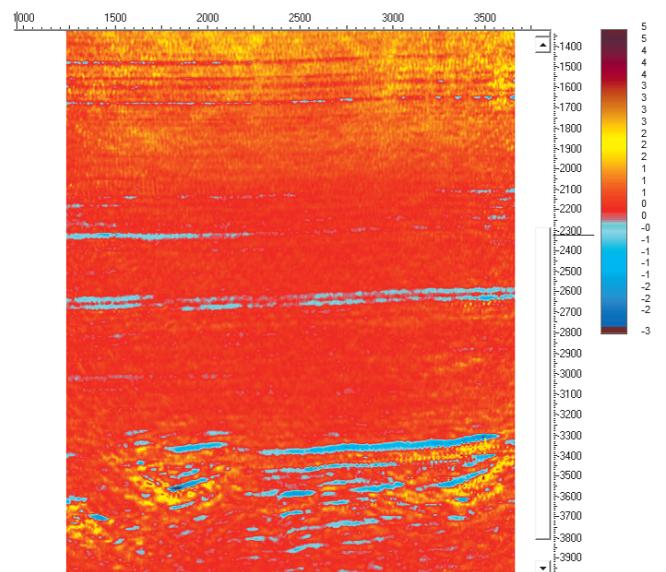


Fig. 19. VPRTM AVO: Fluid Factor

Processing data acquired as per the VPRTM method for a field in West Siberia is given on Figure 20. Oil-bearing capacity of the field is associated with Bazhenov suite deposits (green line) and the basement (red line). It is visible that the strongest scattering zones are situated in the top part of the basement. Drilling in these zones yielded oil flow rates substantially greater than in Bazhenov suite.

**Conclusions**

1. A single mathematical approach has been developed to solving the tasks of active and passive seismic acquisition. This approach is based on reverse geophysical tasks theory.

2. CSPD method has been developed for discovering a scattered seismic component. The method has been verified on model and actual data. It demonstrated high accuracy for ultra-weak scatterers.

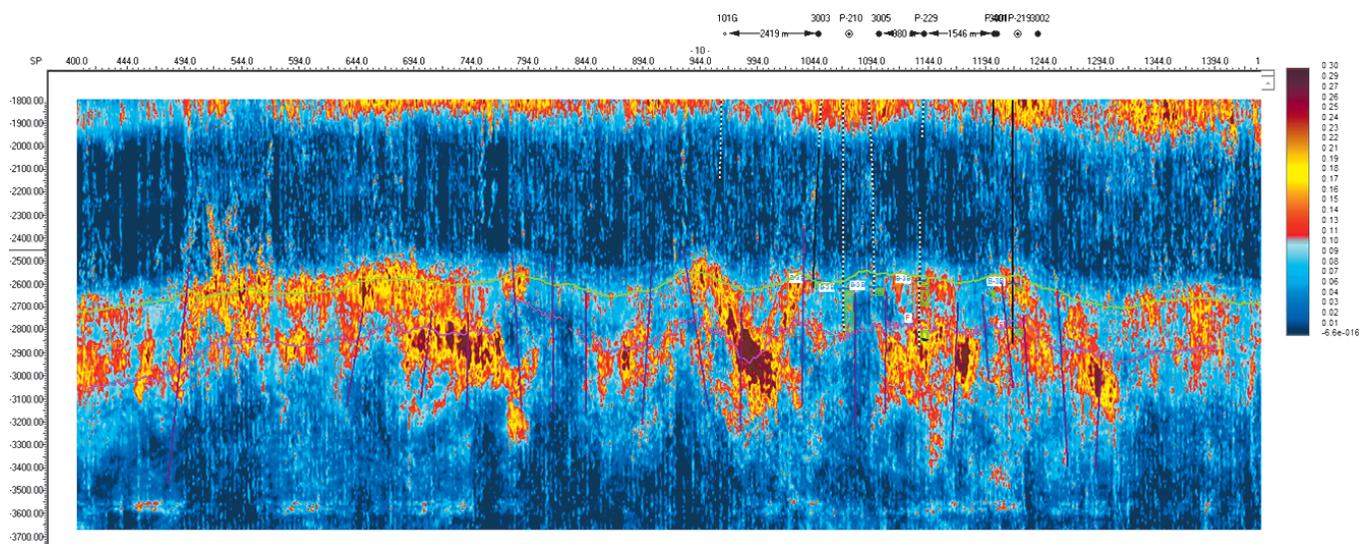


Fig. 20. Diffractor after VPRTM

3. A new method has been offered and implemented for reverse time vector pairs migration (VPRTM). It is effective for both generation of diffraction images as well as for AVO, velocity tomography, impedance, angles, etc.

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# Emission seismic tomography – the tool to study fracturing and fluidodynamics of the Earth crust

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**Abstract.** The article presents the results of seismotomographic monitoring of emission sources associated with fractured zone, tectonic faults and fluid filtration in the high permeable rocks. It is shown that the Earth's natural seismic noise recorded by surface array can be used to study the geodynamic processes caused by the presence of such inhomogeneities. The source of useful information is the extremely weak spatially coherent component of the seismic wave field – the seismic emission generated by background deformation in the energy-saturated volumes of rocks. Additional external technological and natural impact activates latent volumes of geophysical heterogeneity, which reveals new emission targets hidden in the background state. It makes to conduct additional exploration of the field within a radius of several kilometers during hydraulic fracturing.

The article also touches on the history of discovery of the seismic emission phenomenon and the mechanisms of generation of a low-frequency branch of emission as a result of amplitude instability of envelopes of high-frequency acoustic oscillations excited as a result of energetic impact on the medium. Low-frequency emission (1-100 Hz) provides the remote study of high-frequency (1-100 kHz) emission oscillations in the energy-saturated volumes located at a great distance from the seismic array.

**Keywords:** emission seismic tomography, seismic emission, structurally inhomogeneous media, oil and gas field

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## Introduction

The phenomenon of endogenetic seismic emission was formally registered as an invention in the 1980-s. Authors of this discovery are L.N. Rykunov, O.B. Khavroshkin, V.V. Cyplakov (Rykunov et al., 1983), though experimentally-backed assumptions on existence of weak seismic energy sources associated with strain processes within the Earth's crust, had been previously published by other Authors as well starting from the century before the last one (Darwin, 1965; Golicyn, 1960; Gamburcev, 1960; Nanney, 1958; Zhadin, 1971; Gordeev, Rykunov, 1976; Naumenko, 1979; Leet, Leet, 1962). The Authors of the invention however have to be given credit for their firm pursuance of their scientific opinions and the existence of this effect itself. Results of the works by L.P. Rykunov, O.B. Khavroshkin and V.V. Cyplakov evoked a heated scholarly discussion. Their opponents attempted to overturn the existence of seismic

emission, including experimental ways (Galperin et al., 1987). Inconsistencies of the first experiments were associated with imperfections and differences in equipment, methods and technologies of investigations. It was also due to the fact that the phenomenon under examination is very complex in its space-time structure, and the intensity of endogenetic emission is very low. It was often on the threshold of used recorders' sensitivity readings. The very idea of existing seismic emission was completely out of classical continuum mechanics framework and the idea that natural noise of the Earth forms only due to multiple surfaces sources. The disputes gradually subsided along with the development of a new lithosphere model as a geo-environment which represents an open non-equilibrium non-linear dynamic structure, which shows variability of parameters, with hierarchy-block structure and energy saturation (Lukk et al., 1996). As equipment was improved and processing methods were upgraded, new multiple test results emerged which confirmed existence of seismic emission, no longer possible to contest.

However at the first stage using single-point narrow-tape recorders, Authors of the invention managed to prove by experiments (Havroshkin, 1999) that low-frequency seismic noise ( $f > 1$  Hz) was modulated by different strain processes, such as luni-solar tides, storm microseism, waves from remote strong earthquakes and explosions, Earth's own oscillations, etc. In seismo-active regions they found (Havroshkin, 1999) typical features of high-frequency noise which appear during preparation of earthquakes and during relaxation of stress in the Earth's crust after the earthquakes. Authors of this invention attributed this fact to existence of endogenous sources of seismic emission which is a component of natural seismic background of the Earth. They suggested that sources of emission are associated with various-scale structural-geologic and energy (stress concentrations, thermal gradients) uniformities, whereas intensity of emission is controlled by external low-frequency strain impacts. Indeed, further direct borehole investigations did show that increase in the level of seismic and acoustic noise corresponds to intervals of fragmentation and higher fracturing, active micro-movements of the Earth's crust and tectonic faults and fractures (Diakonov et al., 1989; Diakonov et al., 1991; Diakonov et al., 1990; Astrahancev et al., 2007). I

n particular, it was shown that increase in the level of noise and its variations relates to location of ore intervals and an oil reservoir (Diakonov et al., 1989; Atlas of Temporal Variations..., 1994). During seismic acquisition, appearance of induced geodynamic noise was encountered in up to 40 Hz frequency range near a hydrocarbon deposit (Maximov et al., 2015). A large number of test works established that recorded seismic emission activity was not stable in time and space, and possessed selective sensitivity to frequency of impact, however the emission response may differ from impact in frequency (Havroshkin, 1999).

Seismic emission signals may have various shapes (Havroshkin, 1999), but often they are represented by pulsed or noise-like temporal relations. Signals from multiple sources may superimpose during recording and interfere. Moreover, emission signals may be extremely low, completely buried in the noise on single records. Sources of such signals are impossible to localize by conventional seismological methods, based on establishment of seismic phase arrival time from microevents. For studies of seismic emission, a special method was suggested and patented which was later titled seismic emission tomography (Nikolaev et al., 1983). It enables to identify a spatially-coherent component of seismic noise, to localize its sources,

to assess emission parameters (power, spectral composition) (Chebotareva, 2011; Chebotareva, 2012; Tchegotareva et al., 2000).

Input data for emission tomography is represented by noise-like seismic records, recorded by a multi-channel sensors array. These may be recordings of natural seismic noise from the Earth, coda-waves from remote earthquakes and explosions, industrial noise. Recording sensors are placed on the surface or in holes. Even a small deepening of sensors, for first tens of meters is useful and allows to significantly reduce the level of local random noise and to increase sensitivity of the method. During implementation of algorithms, by introducing temporal signal delays, the seismic antenna is adjusted to amplify signals from different parts of the environment. This is followed by calculation of a functional which provides accumulation of information via channels and time. Location of emission sources corresponds to the location of the functional's maximum values which exceed the value of confidence interval of the purely noise field (Chebotareva, 2011; Chebotareva, 2012; Tchegotareva et al., 2000). Therefore, if emission sources are absent, then we will gain an image with an even distribution of intensity. Statistical diversion of brightness values is established by the time of signal accumulation. If sources of seismic emission are present in the geo-environment, then a bright "cloud" will show up on the image and its contours are defined by geometry of the emission region.

Emission tomography was initially used for seismo-geologic surveys in geothermal, seismo-active and volcanic regions. Algorithms were developed, to be applied in time and frequency domain, for 1-component and 3-component recording, which enables to operate in a wide range of spatial scales up to the Earth's deep lithosphere (Chebotareva, 2011; Chebotareva, 2012; Chebotareva, 2017; Tchegotareva et al., 2000). Adaptation of emission tomography for operations at hydrocarbon fields required to work out additional algorithms which make it possible to eliminate effects from intensive spatially-coherent industrial noise (Chebotareva et al., 2008; Chebotareva, 2010a; Chebotareva, 2010). Approximate algorithms for ray tracing were also developed which enable to significantly speed-up calculation time for horizontally-layered, gradient velocity models and layered environment models with complex boundary geometry. The correct consideration of a velocity model allows to increase sensitivity of the method and to provide a more accurate 3D-adjustment of emission sources (Chebotareva, 2018).

Seismic emission tomography, despite its strong potential, is not sufficiently applied in hydrocarbons development. In our country there are some studies on application of different modifications of the method to monitor fracking jobs and to exercise methods for deriving geological information applying emission and scattered waves attributed (Gapeev et al., 2014; Alexandrov et al., 2015; Kuznetsov et al., 2016). In other countries emission tomography is also successfully applied by servicing companies to monitor hydraulic fracturing and high-activity fracture zones. Examples of such companies are MicroSeismic, Inc. and Global Geophysical Services, Inc.

Since emission tomography may operate with not only pulsed signal but with noise-like signals as well, it allows to extract more descriptive information than micro-seismic monitoring: to study not only microevents but also weaker in energy dissipative processes during formation of the environment, which are not accompanied by micro-earthquakes. This Article shows examples on identification and 3D localization of emission activity sources associated with tectonic faults, open fracturing, fluid filtering in highly-permeable rocks. All the images were generated applying seismic emission tomography algorithms.

## Results and Discussions

Seismic records acquired at hydrocarbon fields during seismic acquisition often show intensive industrial noise associated with the field development processes. Random additive diffuse noise is easy to suppress, but since industrial noise sources are associated with some specific objects, industrial noise is spatially coherent. In addition, sources are not always located on the surface, for example, in case of a ‘noisy’ well. When using emission tomography, such noise may create shielding effect. This means that bright sources of strong industrial noise will show up on the images of the studied object, where weak deep sources will remain unnoticed against them. When adapting emission tomography methods for hydrocarbon fields, adaptive and rejector

spatial filtering methods were developed, which allow efficient elimination of effects caused by coherent noise events (Chebotareva et al., 2008; Chebotareva, 2010a, Chebotareva, 2010b).

But what turned out to be more interesting is that an industrial noise may be effective if used as a sounding signal. It creates an additional seismic ‘illumination’ of the geo-environment and allows to identify uniformities with strong scattering, reflective properties, or underground resonators. Fig. 1 shows two of such examples – image of a tectonic fault and a natural fracture (a side boundary of unstable block of rock). Image of the fault (Fig. 1a, b) has a complex spatial structure. It is known that the internal part of a fracture zone is characterized by a high level of fracturing (first tens and hundreds of meters). Towards the center of the fracture density of fracture rapidly grows, the central zone (centimeters – meters) becomes filled with crushed, fragmentized material. Seismic wave velocity of host rocks exceeds velocities inside the fracture by dozens of percent. In other words, the fracture represents low-velocity waveguide. If the source of industrial noise is located rather close to the fracture, then the low-velocity zone captures the energy of the industrial noise. Boundaries of the natural waveguide are not flat and not absolutely firm, therefore a significant part of seismic energy permeates through walls of the waveguide, and it becomes visible for emission tomography. Image of the fracture zone indicates that a large part of energy from industrial impact during development stops at deep horizons exceeding 6 km.

Fig. 1c shows an image of a natural fracture, whose internal part, as we can expect, is also filled with highly fragmented rocks. It showed up at the time of perforation blast. However the main energy from perforation blast lies in a higher frequency range than emission of the fracture. In other words, in this case we either observe a trigger effect, or non-linear transfer of energy from perforation blast to lower frequencies.

Fig. 2 shows horizontal slices of 3D images at the depth of the horizontal wellbore. They demonstrate how

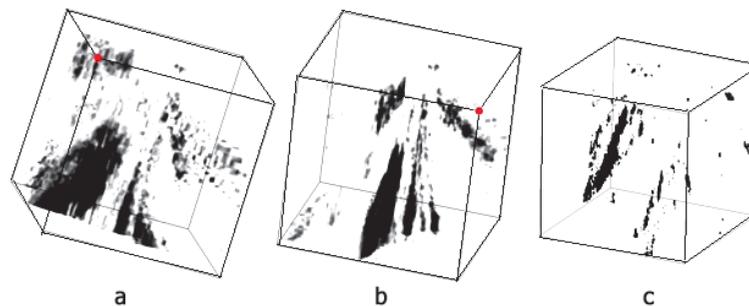


Fig. 1. Application of industrial noise to «illuminate» tectonic faults, a, b – images of a tectonic fault with turned isometric projection, c – image of a natural fracture. Size of the edge of studies objects is 6 km (a, b) and 3 km (c)

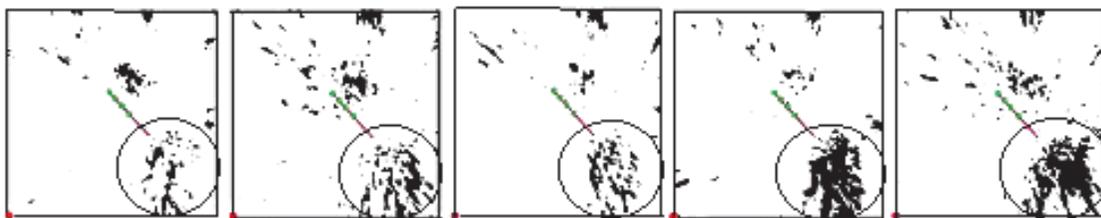


Fig. 2. Development of fluid outflow from borehole in high-permeability part of the rocks. Horizontal slices of 3D-images at the depth of a horizontal borehole. Time vector from left to right

fluid runs out of the well. Fluid spreads towards greater rock permeability. Radiated emission is associated with pressure fluctuations and micro-destruction of rocks when pore pressure grows behind the filtering front.

As mentioned previously, seismic emission response of rocks is enhanced by external effects. One of such industrial impacts comes from hydraulic fracturing. During fracking, by using microseism monitoring within first hundreds of meters they normally study characteristics of the breakdown, design of the disruption, absolute permeability of the bottomhole zone (Maxwell, 2010; Economides et al., 2002; Rothert, Shapiro, 2007; Shapiro et al., 2002; Alexandrov et al., 2015). Since emission tomography allows to study a thinner structure of the stress field, during emission seismo-tomographic monitoring it becomes possible to observe activation of open fracturing zones and tectonically unstable blocks in a much larger volume of the environment. Tests results show that in case of such local industrial effects, distribution of active emission clusters significantly changes within several kilometers radius from perforation zone, and in various ways in different frequency ranges (Chebotareva, Volodin, 2012;

Chebotareva, 2017; Volodin, Chebotareva, 2014).

Images of the environment were computed in different frequency ranges within 10-100 Hz. It was established that micro-earthquakes, whose arrival amplitudes are clearly identified on single records, show up in the lowest frequency range. From the very start of formation impact, sources of micro-earthquakes are localized over the entire studied object which represents a hexahedron with 3 km edges (Chebotareva, Volodin, 2012). They can not be unambiguously associated with relaxation diffusion of disturbances in pore pressure. A better explanation is a trigger effect initiated by changes in stress-strain state of the rock mass.

Rocks fracturing zones show up on emission images in the medium frequency range. Partially they are visible prior to hydraulic fracturing (Fig. 3a). However, during growth of pressure in the environment during fluid injection the size of emitting cluster sharply increases (Fig. 3b), identifying latent fracturing zones inactive in background conditions. After completion of operations upon relaxation of stress in the geo-environment, distribution of emission clusters returns to previous shape (Fig. 3c).

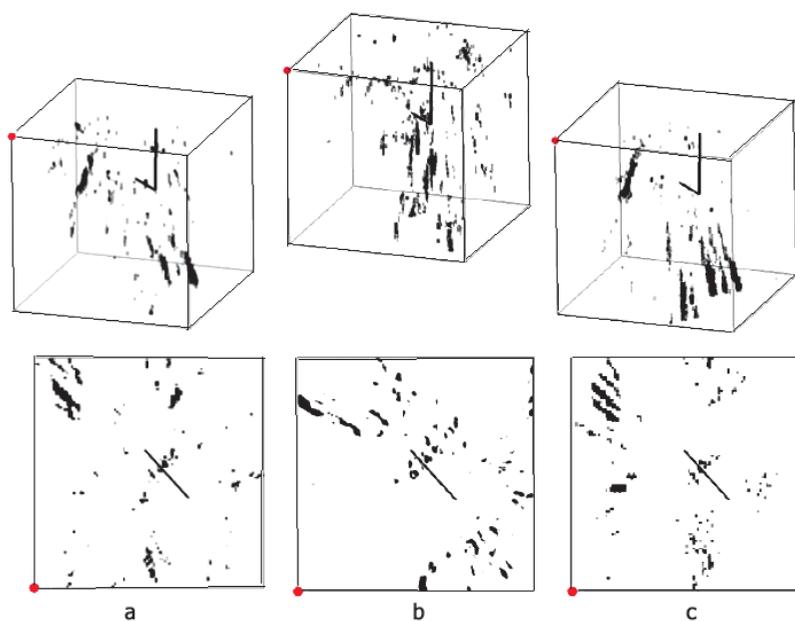


Fig. 3. Distribution of emission activity in zones of structural inhomogeneities (porosity, open fracturing) a – before, b – during (pressure growth interval) and c – after hydraulic fracturing. Size of the studied object's edge is 3 km

Behaviour of emission clusters in the upper frequency range has some distinctive features. In background state before and after hydraulic fracturing distribution of emission sources is similar in the medium and upper frequency ranges. The external impact however destroys the structure of high-frequency emission cluster. Distribution of image intensity becomes even (Chebotareva, Volodin, 2012). It is possible when environment in this frequency range does not emit or emits unevenly along the entire object. As pressure grows, emission «luminosity» is localized and drawn towards deformation strips, highlighting the location of unstable block, at which basement the strongest micro-earthquake occurs (Volodin, Chebotareva, 2014). Its source is at more than 2 km distance from perforation zone. After pressure release, distribution of intensity in the images becomes even again. It returns to initial background shape after relaxation of stress in the rock mass.

Fig. 4 shows emission image of the formation's disrupted area at the time between hydraulic fracturing in case of a multi-stage hydraulic fracturing. Emission signal is provided through relaxation energy of perturbed stress-strain state of the formation. Horizontal projection clearly shows the geometry of hydraulic disruption, non-symmetric in relation to the well. Since distribution of emission sources is essentially not flat, in this case we can observe a zone of bulk formation disturbance.

### Conclusion

Results of emission seismo-tomographic monitoring at hydrocarbon fields under development demonstrate that zones of fracturing, tectonic and fluidal activity may be discovered and localized with background seismic noise records. However more substantial information, with further exploration of resources within a few kilometer radius, may be acquired with different types of external stimulation, such as hydraulic fracturing, strong industrial noise, seismic waves passing from remote earthquakes and explosions. Additional information may be extracted from seismic data re-processing,

provided that the works are conducted with improved high-sensitivity seismic modules. Emission tomography and seismic acquisition are two complimentary methods. Seismic acquisition aims at identification of horizontally extending contrasting velocity boundaries. Emission tomography aims at identification of local non-uniformities which may not cause contrasting reflections. It applies different physical principles and utilizes seismic emission effects undetected by conventional seismic acquisition methods.

The studies of rocks' response to natural and industrial impacts is a fundamental scientific challenge. In order to develop emission seismo-tomographic technologies, which could be methodically available to servicing companies, it is necessary to carry out additional experimental and theoretical studies. Reliable data interpretation requires experimental statistics on the parameters of emission samples with an accurate connection to geological objects. It is also necessary to further develop the theory on seismic emission generation and propagation of seismic signals in structurally non-uniform environments. Despite the fact that 35 years have passed since seismic emission effect discovery was recorded, the mechanisms of seismic emission are still not clear.

Very often studies dedicated to seismic emission associate its appearance with a large number of micro-breakages, including those during relaxational diffusion of pore pressure perturbances. Conventional monitoring of hydraulic fracturing is conducted through borehole observations in order to record micro-earthquakes within hundreds – first thousand Hertz range. Presence of a continuous emission component is interpreted as superimposition of a large number of consistent pulsed signals from multiple shear fractures. The above results however show that emission effects enabling to visualize hydrodynamic processes associated with hydraulic fracturing are observed at much lower frequencies – tens of Hz.

By using resolution of the problem for a circular fracture which suddenly stops its development (Madariaga et al., 1976; Aki, Richards, 1983), we will

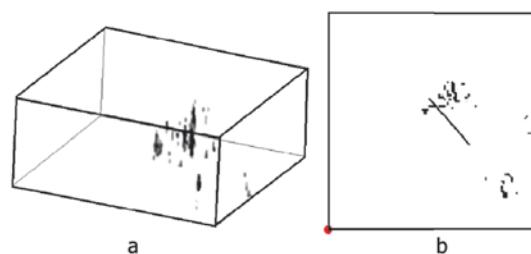


Fig. 4. Hydraulic breakage zone at a time between hydraulic fracturing during a multi-stage hydraulic fracturing. Horizontal edge is 3 km, a – isometrical projection, b – horizontal projection at the depth of a horizontal borehole

gain estimation of a typical radius of multiple fractures:

$$r = 0.32 \cdot V/f = 20 \text{ m,}$$

where  $V = 3 \text{ km/s}$  – seismic waves velocity,  $f = 50 \text{ Hz}$  – emission radiation frequency. Such estimation is not true. Sizes of anticipated “multiple faults” are too large considering that normal sizes during hydraulic fracturing are only equal to first hundreds of meters.

A better approach to description of emission radiation mechanisms on the frequencies starting from first units to first hundred Hertz is based on non-linear properties of structurally inhomogeneous media. To present moment, there are several mechanisms developed taking into consideration non-linear nature and block discreteness of the geo-medium (Bovenko, 1987; Krylov et al., 1991; Dinariev, Nikolaevsky, 1997; Dinariev, Nikolaevskiy, 1993; Nikolaevsky, 1996; Garagash, 2002; Sibiryakov, Bobrov, 2008). They describe generation and transfer of emission radiation energy up and down the spectrum in the form of harmonics and sub-harmonics.

Recently a new mechanism of seismic emission generation was suggested on the frequencies enveloping the micro-oscillations elements of structurally inhomogeneous geo-medium (Volodin, Chebotareva, 2014). Movement equations were derived for a medium model in the shape of one-dimensional chains with Hertz nonlinearity. Modern geophysics commonly applies such models of granulated media not only for description of soft soils, but also for conventionally monolithic grainy and crystalline rocks. Experiments have proved that distribution of stress in volume is not uniform in granulated media during surcharge and vibration effect. Application of stress-optical material allows to visualize formation of a grid of power chains which bring all the load to the medium. The study (Volodin, Chebotareva, 2014) shows that when examining multi-scale movements, the chain movement equation has the shape of the nonlinear Schrödinger equation. We know that under certain conditions for nonlinearity and dispersion parameters, there appears modulational instability in solution of this equation which is expressed in a spontaneous amplitude modulation of radio-frequency carrier. When modulated wave propagates in nonlinear medium, its detection occurs (Zarembo, Krasilnikov, 1966), which results in only a low-frequency component remaining, which is recorded at large distances from the source. Correlation between the main and modulational frequency depends on structural parameters of the medium and is normally equal to several orders of magnitude.

For this reason on seismic frequencies equal to tens of Hertz it is possible to study remote areas of structurally

inhomogeneous inclusion with micro-oscillations frequency from one to hundreds kHz. Physical simulations using core samples from oilfields show that during straining the core samples and vibrational impact, it is effectively possible to observe generation of dynamically bound radiation in 10-100 Hz and 5-20 kHz range, whereas the dynamics of intermediate frequency range is significantly different (Chebotareva et al., 2017).

## Conclusion

1. The emission seismic tomography method allows to identify tectonic faults, open fractures and porosity, to study geophysical processes in the zones of structural and fluidal inhomogeneity of the natural mass using multi-channel recordings of the Earth's natural seismic background recorded on the surface.

2. Industrial and natural external impacts on the geo-medium activate areas of structural inhomogeneity which are hidden in background state. This allows to conduct additional exploration in the field at the stage of development, to identify promising formations and missed deposits. In particular, during hydraulic fracturing it is possible to conduct follow-up exploration within a few kilometer radius.

3. To ensure reliable data interpretation and development of effective servicing technologies, it is necessary to conduct field studies of seismic effects observed at hydrocarbon fields, with an accurate geologic correlation of emission objects.

4. It is necessary to continue development of the theory on seismic emission generation and propagation of seismic signals in structurally inhomogeneous media.

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# Use of induced acoustic emission of reservoirs for the detection and recovery of hydrocarbons

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**Abstract.** The results of a study of seismoacoustic emission appearing in a saturated porous geological environment with forced acoustic impact on cores and in wells are presented. It is shown that the wave action effectively influences the increase in permeability relative to the initial value and the acoustic emission of a saturated porous medium caused by the wave action serves as a reliable source of information on its reservoir properties.

The hydrostatic pressure gradient contributes to the acoustic emission mechanism, which creates fluid filtration. In this case, the greater the core permeability, the wider the emission frequency band, the smaller the permeability, the narrower the band of the spectrum, which approaches the form of a discrete set of frequencies. Similar data were obtained in oil reservoirs, where a continuous spectrum is characteristic of porous sandstones of terrigenous reservoirs, and single narrow-band spectra, for fractured carbonate reservoirs.

The principle of excitation of high-intensity waves of elastic energy and registration of waves of emission origin in the reservoir provides reliable information on reservoir productivity in both perforated well and non-perforated well, and can give recommendations on the selection of the perforation interval and also stimulate the inflow of oil from the reservoir.

**Keywords:** seismoacoustic emission, acoustic impact, saturated porous medium, spectrum of induced acoustic emission, reservoir permeability.

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## Core Studies

Elastic energy emission in a productive reservoir bed which shows mixed saturation and a wide range of reservoir properties, has its peculiarities as compared to seismic-acoustic emission of geologic environment caused by its stressed state in case of no saturation. First of all this is associated with presence and properties of internal seismo-acoustic emission sources in these media. A number of theoretical and experimental works have been dedicated to investigations of emission mechanisms in heterogeneous system with different reservoir saturations (Chebotareva, Volodin, 2012; Pikovskii, 2003; Volodin, 2003; Rudenko, 2006; Tertsagi, 1961; Nikolaevskii, Stepanova, 2005; Vilchinskaya, Nikolaevskii, 1984; Kurlenya et al., 1993; Dryagin, 2013).

Seismo-acoustic tomography of an oil pool based on its high emission potential and temporary stability of elastic energy radiation processes provides a reliable source of information for oil and gas prospecting. Special role is played by studies of the environment's response

to external mechanical impact and indirect impact occurring in the medium itself under the influence of the so-called seismo-acoustic emission (Dryagin, 2013; Khismatullin, 2007). This very mechanism is the most effective tool for a local impact on saturated medium which may change effective permeability of oil and in this way improve its reservoir properties. In such a case, radiation from induced elastic energy field covers the range from first Hertz to dozens kilo Hertz and depends on the structure and composition of saturated porous medium.

Low-frequency emission signals are formed in dry sands as well (Vilchinskaya, Nikolaevskii, 1984) while the vibrations train spreads from radiation source to the receiver. As the wavefront area expands, the duration and number of low-frequency vibrations within acoustic emission range grow as well. The origin of low-frequency vibrations is associated with a significant relative displacement of particles under the conditions of their contraction, i.e. compaction of soft sands, whereas in case of granite contraction, it is associated with start of fracture development and the sample falling into pieces (Voronina, Epifanov, 1980). In this case stages of granite crushing are accompanied by acoustic emission radiation, starting from 1-12 kHz range, appearance of

fractures in 100-800 Hz, and at the end of breakdown, the signal's spectrum concentrated within the 2-50 Hz range with its maximum at 12.5 Hz.

Studies by Nikolaevsky (Nikolaevskii, 1992; Nikolaevskii, 2005) quote models of forming dominant frequencies in formations saturated with water and oil associated with filtering and changes in phase permeabilities under the influence of vibrations of natural or artificial origin. Analyzing what caused a positive effect of a weak seismic impact on increase in the final oil recovery rate, the Author accentuates mechanisms of forming high-frequency elastic vibrations in the formation due to frictions at the contacts between fractures and grains.

Low-frequency vibrations in oil- and water-saturated formation have been observed by many Authors (Belyakov et al., 2004; Alekseev et al., 2004; Kurlenya, Serdyukov, 1999; Barabanov et al., 1987; Poznyakov, 2005; Dangel, 2003; Engelbrecht, 1988), what is more, the frequency range almost coincided and was within the 1.5-50 Hz range in the form of discrete frequencies, for example 18, 20, 24 Hz, etc.; it all depended on properties of the object in the experimental zone. The main peculiarity in this case was that the same frequencies were observed for both oil-saturated formation and water-saturated formation. Of course, everything depended on the water/oil relation in the formation and its filtering properties.

Application of wave action sources with various narrow impacting parameters and attempts to justify the mechanism only by these impacting parameters do not allow to evaluate how the wavefield interacts with porous medium in a single process which covers a wide range of frequencies and interaction between frequencies.

Studies (Venkitaraman, 1995; Roberts, 2000; Roberts, 2005) quote results of a successful application of wavefield energy in ultrasonic range to remove various hard particles from saturated porous medium.

Thus, after ultrasonic treatment of core with 20-250 W/m<sup>2</sup> wavefield at 20-80 kHz frequencies (Venkitariman, 1995), permeability of saturated sandstone and limestone grows by 3-7 times, at the same time efficiency of deep cleaning from hard clay particles, mud and filtrate is no more than 2.5 inch.

Resulting from experiments with core samples (Roberts, 2000) acoustic energy with 300-4500 W/m<sup>2</sup> capacity impacting at 20 kHz frequency allows to efficiently remove paraffin/asphalten deposits in a porous sandstone and to restore its effective permeability up to 12-15 cm depth.

The study (Mitrofanov et al., 1998) reviews the results of laboratory investigations on how acoustic impact (AI) affects phase permeabilities on oil, on water and displacement of oil by water in Terrigenous reservoirs. The experiment was held considering

formation conditions and showed that the most sensitive to acoustic impact is the oil's bound phase, which keeps changed properties for longer and predetermines viscosity of colloidal hydrocarbons system in general. The study points out that acoustic impact lasting 10-15 minutes leads to increase in permeability on oil by 17-40%. Effective viscosity of oil in this case diminishes by 8-9%, whereas the share of immovable phase reduces twofolds as compared to the initial one. The Authors link this mechanism to re-distribution of hydrocarbon molecules through weakening of hydrogen connections. Parameters of the acoustic effect field are close to parameters in previous studies: specific capacity of 20000 W/m<sup>2</sup> at 19 kHz frequency.

Wave impact in low frequency domain of 1-500 Hz also shows multiple examples of increasing mobility of multi-phase fluids in productive reservoirs. Example of analysis of low-frequency dynamic effect in the study (Roberts, 2005) shows validity of interest in studies of fluid filtering mechanisms in porous medium using laboratory tests and generation of relevant theoretic models. This work informs on properties of the fluid flow with an abruptly different viscosity in core's porous space under the influence of external low frequency wavefield. At the same time, there is a principal difference in behavior of the fluid flow when the wavefield is imposed, in particular reduction in pressure differential in cores for low-viscosity fluids (decane + water solution) and increased pressure for high-viscosity fluids (oil + water solution). The reason for such diverse behavior of fluids is in different mechanisms of oil and decane wetting with the surface of core's water-wet porous space within a dynamic wave effect field. This study demonstrates for the first time that low-frequency impact in core is as effective in restoring permeability of porous space as is the high-frequency impact. Since low-frequency impact penetrates deeper into the geologic environment, it is more preferable technologically. At the same time, the study highlights a contradiction: on the one hand, low-frequency effect mobilizes oil on a priori mobile water and thus increases the share of oil in the fluid, on the other hand, oil, being more viscous, closes the pores as soon as it begins to move.

The study has established the link between mechanical stress and strain caused by it under the influence of an external dynamic wave impact with changing porous pressure. This pressure does not exceed 2.4 kPa when reaching threshold stress value of dynamic wave effect with 600 kPa amplitude, when changes in fluid flow were noticed. It is also pointed out that effect of changing porous pressure is more important for increasing the porous flow rather than mechanical stress caused by external impacts.

It is necessary to mention that changes in porous pressure may occur as a result of phase transitions of

hydrocarbons and their subsequent degassing under the influence of external acoustic field (Stepanova et al., 2003; Stepanova et al., 2005) at various frequencies. At the same time pressure may fluctuate from 50 kPa to 1000 kPa depending on gas factor and parameters of the wave effect.

Stress-strain behavior of the porous medium causes acoustic emission, whereas saturation nature influences accumulation of elastic energy and its release in the form of acoustic emission (Khismatullin, 2007). In order to initiate acoustic emission signals, it is enough to have a minor external disturbance whose amplitude is measurable to natural background of acoustic emission in stress-strained state. This study indicates that cores saturated with oil have maximum accumulated energy and therefore a high energy release speed which has a pulsed nature. Water-saturated cores showed stable decline in energy release, and the dispersion of acoustic emission signal in water was at least 2-3 times less than in oil. This trend was also discovered in an oil pool during investigations on the surface and downhole (Dryagin, 2013; Grafov et al., 1998; Dryagin et al., 2005; Dryagin, 2001).

So, considering a number of studies dedicated to mechanisms of wave effects on saturated porous medium, porous pressure may change within 2-3 orders of magnitude. At the same time, there is an indication on pore pressure threshold which leads to fluid movements, as well as on its non-established mechanism.

An obvious connection between emission activity of saturated porous medium and hydraulic pressure in pores which occurs during wave effect, calls for investigation of its mechanisms and quantitative relations between released elastic energy and parameters of the medium.

Processes of acoustic emission activity in cores in stress-strained state, fluid filtering and wave effect conditions were experimentally tested on a UIK-AE unit.

The tests were carried out with core samples from porous, weakly clayey sandstone from formation BS10(2-3) at Tevlinsky-Russkinsky field in West Siberia (Chebotareva et al., 2016). Dimensions of composite core: diameter – 30 mm, length – 90 mm. The first core sample (sample No. 1) has the following parameters: porosity –  $K_{por} = (20.5-21.4)\%$ , permeability –  $K_{per} = (89.31-89.99) \cdot 10^{-3} \text{ mm}^2$ , the second sample No.2 –  $K_{por} = (16.6-16.8)\%$ ,  $K_{per} = (8.02-10.47) \cdot 10^{-3} \text{ mm}^2$ .

Application of stress on core samples and location of measuring sensors are shown on the chart in Figure 1.

Wave emission processes in cores were studied in the conditions close to formation pressures as much as possible. Compression of the sample to pressures resembling formation pressure included two parts: first one – axial compression (P1) in order to create a stressed state corresponding to rock pressure, second

one – hydrostatic contraction of core in order to create formation pressure (P2) of the fluid. Core was previously saturated with residual water in accordance with industry core study standards. During pressure build-up, all fluid pressure parameters and acoustic emission signals were continuously recorded with appropriate sample rate.

Seismo-acoustic tomography of an oil deposit is based on a high emission potential and temporal instability of elastic energy release processes (Khismatullin, 2007; Nikolaevskii, 1992; Nikolaevskii, 2005). The acoustic emission forming in a saturated porous medium is contributed by pressure gradient which provides fluid filtering. In order to study contribution of this effect in forming of acoustic emission, two Terrigenous core samples from Tevlinsky-Russkinsky field with various permeabilities were tested. Tests were also conducted on the UIK-AE unit (Fig. 1), with core samples preloaded with axial pressure P1 within 10-21 mPa range and contraction pressure P2 within 33-35 mPa. Filtering was provided by fluid being fed to core entrance by a plunger pump P4, which resulted in core pressure differential  $\Delta P = P4 - P3$ , established in accordance with its permeability (Fig. 2).

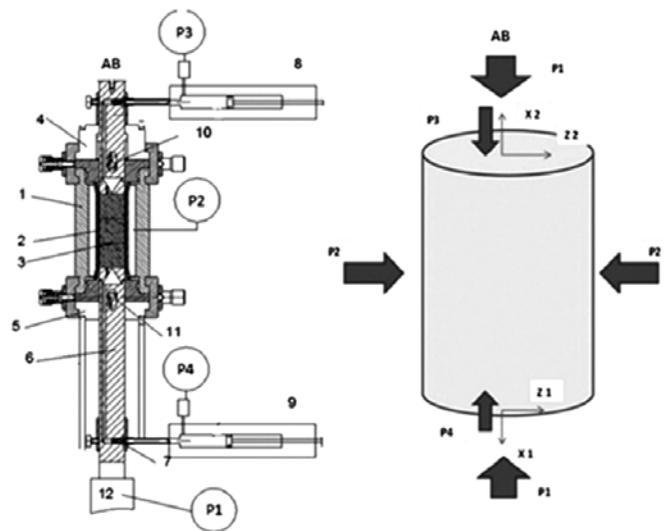


Fig. 1. Core fixing device, force application schematic and location of measuring sensors in UIK-AE unit. P1 – axial compression pressure, P2 – core contraction pressure, P4 – fluid pressure at core entrance, P3 – fluid pressure at core exit, X1 and Z1 – acceleration sensors for longitudinal and shear oscillations at core entrance, X2 and Z2 – sensors at core exit. Core entrance and exit is a conventional notation for feeding the saturating fluid. Main elements of the core holder: 1 – high pressure chamber, 2 – rubber collar, 3 – core, 4 and 5 – folding parts for core fixing and sealing – flanges with O-rings and fixing clamps, 6 – lower footing of a core sample for transfer of axial force and feeding the fluid, 7 – sealed entry choke for fluid input, 8 and 9 – conventional notation of plunger pumps for receiving (8) and feeding (9) the fluid into a core sample, 10 and 11 – measuring sensors of the acoustic emission

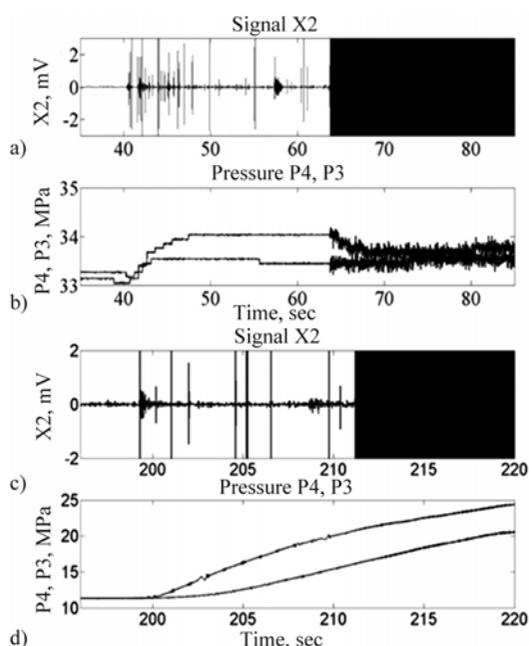


Fig. 2. Fluid movements in core samples, influence of acoustic impact on filtering process

For cores with larger permeabilities  $K_{per} = (89.31-89.99) \cdot 10^{-3} \text{ mm}^2$ , pressure grew faster and reached threshold value within 4-5 seconds, whereas for the second sample with low permeability  $K_{per} = (8.02-10.47) \cdot 10^{-3} \text{ mm}^2$ , growth of pressure did not complete within 20 seconds of observations, under similar conditions when fluid was delivered to core entrance with the pump (Fig. 2b, d). Throughout the entire time of fluid delivery, acoustic emission signals were recorded using sensor X2 at core exit (Fig. 2a, c). Blackened areas on these curves after the 63<sup>rd</sup> second (Fig. 2a) and after the 211<sup>th</sup> second on Fig. 2c correspond to switching-on of the acoustic emitter installed at core exit.

It turned out that during acoustic effect on core, hydrostatic pressure which changes in it along a constant component, also had vibrational nature which was recorded by pressure gages on core entrance and exit (Fig. 1). Pressure variations in this instance depended on core permeability. Trend of their constant components reflected changes in integral filtering properties of all the core which may be evaluated by computation of permeability relative to initial permeability, before acoustic effect according to Darcy's law. But at first it is necessary to examine the vibrational nature of emission and pressure and to compare their energies in order to elaborate a possible model of a physical process in pore space under the influence of external acoustic field.

Such impact field in these tests was represented by emission field of a magnetostriction radiator. The radiator is connected to a wave guide which in its turn is firmly fixed to a core sample. Inside the wave guide is a channel to inject fluid and sensor accelerometer located in the nearest proximity to the core sample.

Filtering in the core sample significantly changes under the influence of external wave impact which in the end leads to changes in absolute permeability of porous medium for any type of fluid which is in its pores. Filtering tests (Fig. 2) attempted to evaluate energy released into fluids in the porous space during acoustic impact, during impact on the core sample. Computation of the energy density of high-frequency pressure vibrations in core was conducted using the  $\Delta P = P_4 - P_3$  difference. Along the amplitude  $P_m$  of this difference we established energy density, high-frequency component of fluid fluctuations depending on the frequency. Frequency in this instance was measured by Hilbert-Huang transform (Huang, 1998).

Interaction of waves in elastic field of finite amplitude with behavior of fluid flow in pore space on core samples was examined in such works as (Venkitaraman, 1995; Roberts, 2000; Roberts, 2005), as well as (Khismatullin, 2007; Mitrofanov et al., 1998). Laboratory tests (Roberts, 2005) showed that bound pore pressure fluctuations occurred during wave impact on core. Pore pressure impulse amounted to 1.2-4.8 kPa, which was enough to stimulate pore fluid flow. They specified main mechanisms of influencing the flow based on breakdown of clay particles and changes in wetting of pores by fluid under the influence of low-frequency wave vibrations from external source. Movements of clay particles relative to fluid of matrix may occur when fluid's local pore pressure is generated in pore space and becomes equal to specified value. Primary source of these pressure pulsations was axial stimulation of wave impact from external activator with field parameters with 600 kPa threshold, when changes in fluid flow were observed.

Tests on UIK-AE unit involved magnetostriction acoustic transducer with 19.3 radiating frequency connected to energy supply which provided radiated power not less than 8 W/cm<sup>2</sup> on the end part of the core sample surface. If acoustic impedance of the core sample is known, then it is possible to establish acoustic pressure reached by this radiator in the core sample, and to compare field parameters of actuators' radiation in these units (Roberts, 2005) and in UIK-AE (Table 1).

Pressure signals, in both cases, are received by sensors installed on the body of the core holder's camera. In the UIK-AE unit, these are pressure gages installed in

Source	Unit	
	Peter M. Roberts	UIK-AE
Parameter	Pressure, kPa / Frequency, Hz	Pressure, kPa / Frequency, Hz
Wave impact	(300–1200)/(25–70)	(1800–2300)/19300
Pressure recording	(1,2–4,8)/(25–70)	(200–500)/(4–100)

Table 1

the hydraulic system's channel in the nearest proximity to core's entrance and exit, allowing to record constant and alternating component of pressure from 0 to 100 Hz (Fig. 2).

Variations of the constant pressure component P4 and P3 in sample No. 1 have a faster character than in sample No. 2 (Fig. 3a, c). In accordance with Darcy's law, knowing pressure differential along the core length, it is possible to establish permeability throughout the entire acoustic impact on core relative to initial one, prior to impact (Fig. 3b, d). Therefore, in case of more permeable core samples, permeability increases in the acoustic field within 20 seconds, reaches maximum which exceeds the start value by 2.5. and then reduces returning to its original value, because constant flow in this test was not maintained. For the second sample with low permeability pressure grew a lot slower (Fig. 3c), therefore its relative permeability changes slower and does not reach maximum value during the test. Moreover, permeability changes have a fluctuating nature which signifies discrete filtering of fluid in the core. It is necessary to point at differences in results of wave impact on the fluid flow in core. The study by (Roberts, 2005) shows that low-frequency impact may stimulate the flow, but pore pressure pulsed under the influence of external field on the same frequency. In tests on UIK-AE unit, wave action at a high frequency caused acoustic emission and pressure variations at a low frequency, therefore the medium itself transforms wave impact into the domain typical of its lowest dominant frequency which is its process of filtering synchronization. The same is mentioned by (Roberts, 2005), given that bound fluctuations of pore pressure

occurred in the conditions of wave impact actuation in the 25-70 Hz frequency.

Figure 4 shows acoustic emission signal spectrum during fluid filtering before acoustic impact. Spectrum analysis was carried out by Short Time Fourier Transform, in a sliding window with given length. Transform parameters were selected in an optimum way in order to identify details of this process in time, which are typical of this kind of a reservoir. In this case the frequency range of spectrogram was from 50 to 20000 Hz. The spectrogram shows a clear discrete nature of frequency set within acoustic emission signal in core at the stage of pressure differential growth  $\Delta P = P4 - P3$ .

The Figure shows changes in total acoustic emission energy in core depending on its permeability. So, in low-permeability core samples (8 mD), the greatest contribution in the acoustic impact energy spectrum is made by high-frequency component, approximately 12kHz. At the same time change in energy during fluid filtering in comparison to a background value is only 2.3%. In high-permeability core samples (89 mD), acoustic emission energy is distributed in a wide range, starting from tens of Hz, which indicates presence of filtering in porous and fracture space. In addition, energy dynamics is equal to 101% under similar conditions. At the same time, absolute energy of acoustic emission have an opposite character. For instance, in a very permeable core sample energy is 7-10 times less than in a stiffer sample.

The method of acquisition of such spectrum consists in selection of a limited number of spectral lines which have maximum value in the signal's spectrum from a

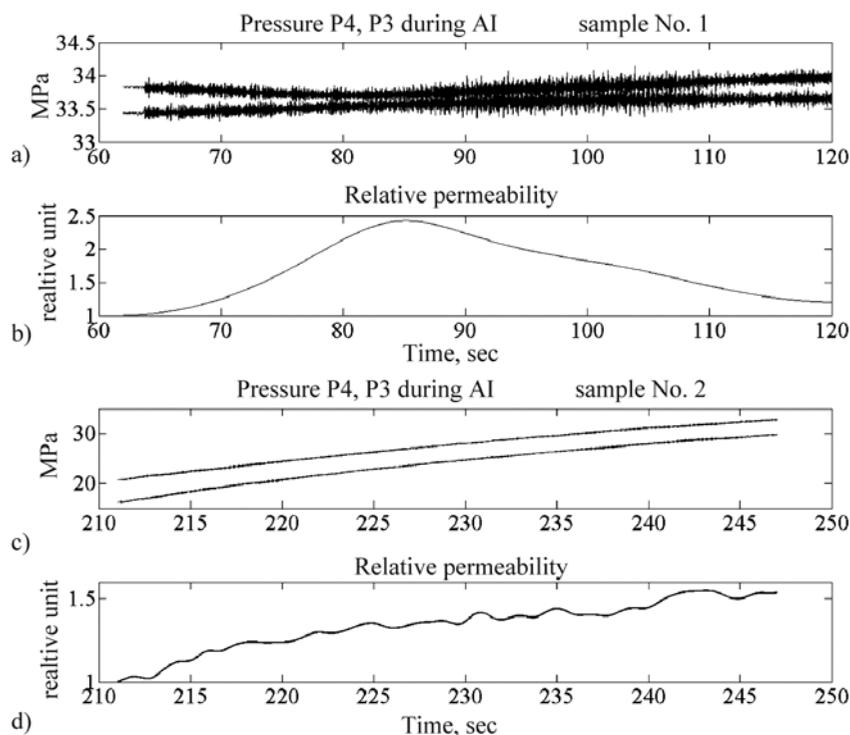


Fig. 3. Changes in relative permeability of core during acoustic impact

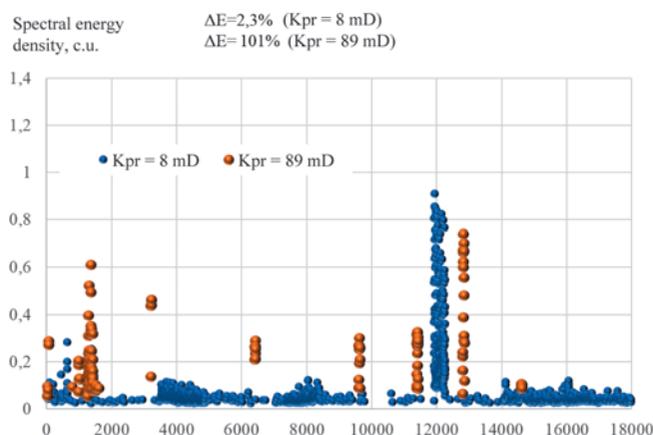


Fig. 4. Discrete range of acoustic emission during fluid filtering (Hz)

sliding window. This signal's spectrum has a discrete nature, and peak frequencies fall into non-linear distribution law over the entire survey range. Such law may for example be represented by non-linearity of the medium with dispersion. In this medium there is interaction of a limited number of waves associated with frequency resonance conditions and wave vectors, i.e. synchronizing conditions (Andronov et al., 1981). In accordance with non-linear system theory, two options are possible in the behavior of non-linear system during interaction of non-linearly connected oscillators, in particular: decay instability and merging of waves. In particular, it is known about interaction of vibrations, for example in a system of three non-linearly connected oscillators, which causes vibrations in the system with combination frequencies. In this case the condition of frequency resonance is followed and it is specified that oscillators may exchange energy when energy of an excited high-frequency oscillator is transferred to two low-frequency oscillators, or an opposite process – merging of low-frequency vibrations. For example, such interaction has a place in a system of three non-linearly connected oscillators described by the following equations:

$$\ddot{x}_i + w_i^2 x_i = \mu \alpha_i x_j x_k; \quad i = 1, 2, 3; \quad j, k \neq i$$

In case of low  $\mu$  – it is a weakly non-linear system.

Its behavior is close to a superposition of quasi-harmonic oscillations with slowly changing amplitudes. Due to a non-linear connection, fluctuations of two oscillators from frequencies  $w_1$  and  $w_2$  cause fluctuations with combination frequencies  $w_1$  and  $w_2$ . The action of low non-linearity accumulates if the frequency resonance condition is met:

$$w_1 + w_2 = w_3.$$

During deformation of a sandstone, which represents a heterogeneous medium, typical of an oil reservoir, and during application of acoustic field, wave processes form in it. Acoustic emission occurring now is

represented by both discrete, impulse component, as well as a continuous noise-like component (Sboev, 1988; Chebotareva et al., 2017; Chebotareva, 2016). Acoustic emission is associated with accelerated movement of dislocations, their exit to a free surface and further formation and development of fractures, as well as other friction processes of local contacts on micro-indented surfaces (Greshnikov, Drobot, 1976; Krylov, 1983; Robsman, 1996). These mechanisms of acoustic emission are suitable for explanation of radiation in kilo-Hertz frequency range, but they do not clarify generation in low-frequency part of the spectrum (tens and hundreds of Hz). In addition, it is necessary to understand mechanism of the connections occurring simultaneously in high-frequency and low-frequency part of the spectrum.

One of such mechanisms is generation of a low-frequency branch of seismic emission, on frequencies enveloping high-frequency vibrations of geo-medium's elements as a result of Lighthill's modulation instability. Such emission component develops within a rock mass in case of a synchronized action of non-linearity and dispersion (Volodin, Chebotareva, 2014). Difference between ranges of carrier wave and modulation wave is established by a scaling factor of the discrete medium, i.e. relation between fragments and their contact zone, and may reach  $10^4$  and over. High-frequency wave and modulation wave interact through instability mode – self-modulation. Such modes are extremely sensitive to any external impact, including acoustic impact according to this technology. The same discrete frequencies were observed when they analyzed induced acoustic emission in wells.

Investigations of fluid system types in sedimentary oil and gas-bearing basins (Abukova, 1997; Sboev, 1998), indicate that one of them – hydrodynamic type – is associated with a chain of processes: geodynamic compaction, increase in potential energy of elastic strain and appearance of micro-seismic noise. It is also mentioned that against external elastic impact there appear quasi-resonance micro-seismic vibrations with amplitudes exceeding amplitudes of instigating vibrations by 2-3 times. As a result, application to fluidal system of even the smallest wave effects, while maintaining the geologic structure, leads to a part of strain energy being transformed into high-frequency energy, which brings about fluid-dynamic non-linear events.

It was confirmed that elastic energy is transformed from one frequency range into another, which stand apart within the range by one-three units of magnitude, with participation of energy from unlimited source of elastic strain from geo-medium's local zone and informative-energy elastic impact from external wave source.

In such a way direct connection between pore space saturation and acoustic emission was established, and

the greatest changes in emission occur in low-frequency area of the spectrum. These changes are likely to be caused by influence from fluid's synchronizing factor in mechanical vibrations of core pore space's structure under the influence of external static load.

The hydrostatic pressure gradient contributes to the acoustic emission mechanism, which creates fluid filtration. In this case, the greater the core permeability, the wider the emission frequency band, the smaller the permeability, the narrower the band of the spectrum, which approaches the form of a discrete set of frequencies. Similar data was obtained in oil reservoirs, where a continuous spectrum is characteristic of porous sandstones of Terrigenous reservoirs, and single narrow-band spectra, for fractured carbonate reservoirs.

Acoustic emission in porous and fracture-porous permeable media increases at fluid saturation and filtering, which is an important informative indication of reservoirs' productivity and filtering properties.

External wave action equally and effectively influences the growth of permeability in a wide range of parameters of the wavefield – from seismic (tens of Hz) to ultrasonic. Thus, wave impact at low and high frequencies leads to similar quantitative growth of relative permeability by tens and hundreds percent relative to initial value.

As the most possible options, mechanisms increasing permeability in the wavefield (for example, increase in wetting of the pores' surface and weakening of hydrogen contacts, which leads to growth of fluid mobility in pores) are a requisite condition of this effect. However variations inside pore pressure carry a more significant information on complex mechanisms of fluid movements in pores and its interaction with the surface, which reflect wave resonance processes of energy flows interaction at various-scale levels.

Finally, increase in permeability at any frequency of external impact, resolution of its changes at fixed impact parameters indicate medium's ability to synchronize filtering processes and to synchronize at multi-scale levels. Accumulation of experimental data and simulation of these processes' models represent a vital task for physics of the oil formation.

### **Well logging operations**

Researching the ways of detailed discovery of residual hydrocarbon resources when developing fields by non-linear geophysical methods based on changes in properties of saturated porous medium under the influence of physical fields, have recently gained new and rather convincing data. The principle of excitation of high-intensity elastic wave energy in a productive formation and recording of emission waves lies at the basis the technology for management of oil and gas extraction at a field.

This principle has been implemented in the following cycle: acoustic impact – acoustic emission logging. Excited waves of elastic energy contribute to initiation of physical-chemical processes in a formation which lead to increase in phase permeability of oil and gas, whereas recorded elastic emission waves carry information on the nature of saturation and filtering capacity of these formations, which makes it possible to conduct controlled impact on the productive deposit.

Technical means allow to implement the entire technology within one running operation using a small 43 mm diameter tool. The software for control, recording, and analysis of oilfield geophysical data provides a possibility to make a decision on optimization of the technology during its application.

We can give many examples of how this technology at present stage of its development is successfully utilized at various fields in our country and abroad. However the main advantage of the technology is in a possibility to adapt it for real-time geophysical conditions of the object's operation. Results of such approach to acoustic impact method can be demonstrated with a case study of LukOIL company's fields in Perm district and in West Siberia. Previously published materials resulted from application of the acoustic impact method in combination with full-scale hydro-dynamic research which showed its high effectiveness (Merson et al., 1999; Mitrofanov et al., 1998).

The study by (Merson et al., 1999) analyzes options of ultrasound in oil extraction and elaborates on why this method is seldom used in oilfield practices. These reasons are mainly in absence of feasibility in selection of development targets and criteria in selection of acoustic field's modes taking into consideration petrophysical properties of reservoir beds and technical state of the "borehole-formation" system in general. These conclusions were made based on detailed hydrodynamic investigations which were planned and executed within the acoustic impact – hydrodynamic survey cycle (Mitrofanov et al., 1998). Unfortunately such studies were not implemented on industrial scale for economic reasons. It was a result of complexity and high labor inputs of performing the hydrodynamic research at a field, as well as due to poor technical state of production parameters control means in those years. At the same time, materials dedicated to studies of reservoir properties acquired in that study provided important formation parameters and showed their changes under the influence of acoustic impact, which became the basis for the technology of real-time process management.

Key formation parameters published by (Mitrofanov et al., 1998) and partially introduced by (Merson et al., 1999) are permeability and hydraulic conductivity of bottomhole and remote zone of the formation, well flow rate, duration of acoustic impact, etc. Fig. 5a, b show

changes of permeability in bottomhole zone and remote zone of a formation during acoustic impact for three wells at different fields. Productive formations greatly differ in their filtering properties which is reflected in the results of the impact.

In the article (Mitrofanov et al., 1998) examines the results of acoustic impact tests at Terrigenous Lower Carboniferous productive deposits at three fields of Preduralsky depression: Pikhtovsky (1), Olkhovsky (2) and Unvinsky (3). Within the depression, Tulavian-Bobrikovian deposits differ significantly from similar objects in the platform part. They are characterized by various diagenetic processes and bituminosity, as well as low clay contents (less than 5%). All of that caused non-uniformity of rocks in wettability in combination with high oil saturation and permeability.

One well was treated at each field in order to enhance recovery. All wells were operational, pumping but significantly differed in initial parameters and running mode. Actual changes in the bottomhole zone and remote zone were seen from hydrodynamic studies conducted before and after acoustic impact. The final criterion of acoustic impact efficiency were the data from long-term oilfield research and economic analysis.

According to hydrodynamic survey results, all wells showed a significant improvement in the state

of both bottomhole and remote zones in terms of the power capacity of working interlayers, permeability, hydraulic conductivity and production rates (Fig. 5, 6). For example, in well No. 174, four working interlayers showed up instead of three, and their total working thickness grew from 7.8 to 10.6 m. Filtering properties especially improved in the bottomhole zone. The well's productivity factor increased from 2.6 to 5.9 tons/day mPa (by 127 %), hydraulic conductivity – from 6 to 12.8  $\text{mcm}^2\text{m}/\text{mPa}\cdot\text{s}$  (by 111 %), permeability – from 11 to 20 mD (by 82 %). The difference between the bottomhole zone and remote zone of the formation is negated and the well plugging index reduces from 1.34 to 1.03.

A similar trend in changing formation parameters is observed in other two wells. In the well with lowest flow rate (well No. 266, Olkhovsky field) a relative improvement of bottomhole zone occurs to a larger extent. In particular, productivity index increased by 312%.

Peculiarities of changes in key filtering parameters of the formation under the influence of acoustic impact – permeability and hydro-conductivity, depend on the formation's initial permeability level. For example, in a formation with less than 5 mD permeability (well 266) growth of permeability is within 31-38% for bottomhole

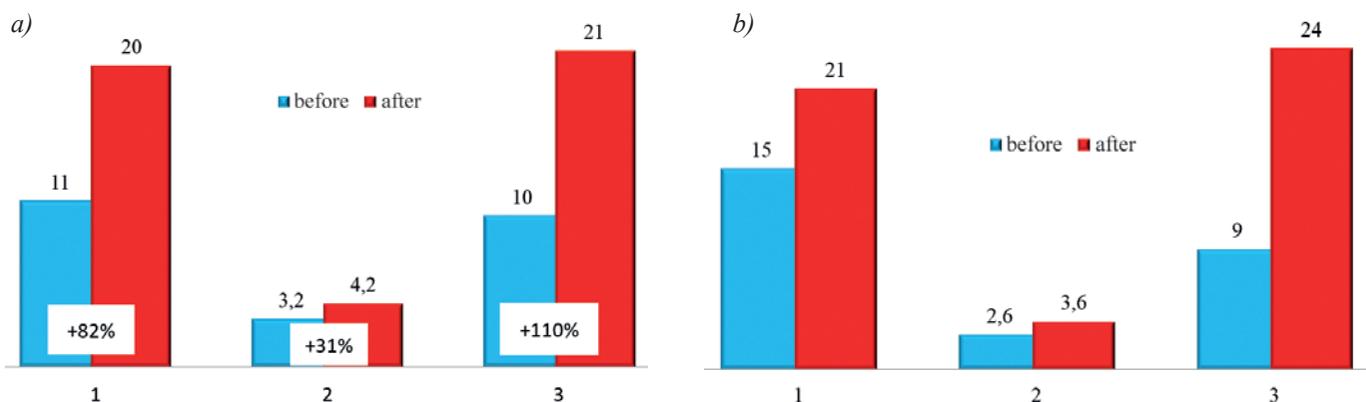


Fig. 5. The change in the permeability of the reservoir during the process of acoustic impact. a) Permeability of the bottomhole zone (mD); b) Permeability of the remote zone (mD). 1 – well No. 174 of the Pikhtovsky field, 2 – well No. 266 of the Olkhovsky field, 3 – well No. 255 of the Unvinsky field

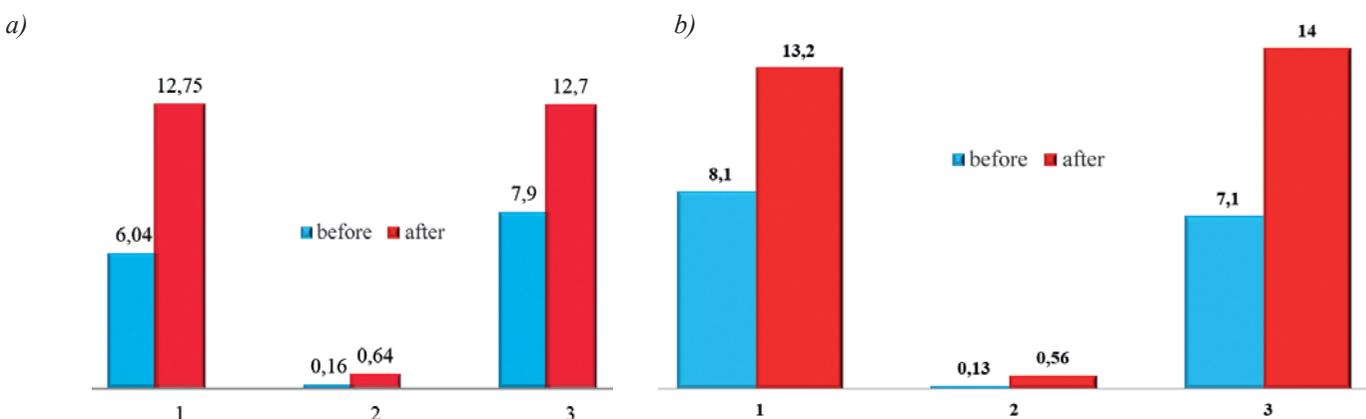


Fig. 6. a) Hydro-conductivity of a formation's bottomhole zone ( $\text{mcm}^2\text{m}/\text{mPa}\cdot\text{s}$ ), b) Hydro-conductivity of remote zone ( $\text{mcm}^2\text{m}/\text{mPa}\cdot\text{s}$ ). Legend on Fig. 5

area and remote area, whereas hydro-conductivity of such formation grows by 300-330%. This justifies a much stronger effect of acoustic impact on the growth of its filtering properties – formation’s working thickness (200%) and productivity factor (312%) (Fig. 7).

But due to potentially low reservoir properties of the formation, flow rate growth (Fig. 8) and cumulative production at this well (Fig. 9) are obviously lower. The duration of the effect (13 months) is however comparable. This leads to a conclusion that acoustic impact method can be and needs to be applied in low-permeability reservoirs.

Well 174 may serve as an example of acoustic impact’s final effect. This well passed the entire dynamic cycle of flow rates, including growth, stabilization and decline up to pre-treatment levels. The entire period of well’s operation may be divided into five stages, which significantly differ in average daily flow rates. From 1983 to 1986, free flowing wells yielded maximum flow rates – 68.2 tons/day on average. Then, until 1994 an abrupt decline in flow rate occurred up to 4.6 tons/day followed by growth and stabilization at the level of 16.9 tons/day. Post-acoustic period of operation is characterized by a significant growth of flow rate, on average up to 47.6 tons per day, or re-establishment of initial level by 69.8%. Growth of flow rates before acoustic impact (1995) was caused by treatment of the bottomhole area with stabikator solvent or hexane fraction

in combination with nitrilotrimethylphosphonic acid.

Throughout the entire period of acoustic effect (16 months), accumulated production reached 23.5 thousand tons, or 30.4% from cumulative production over 12.6 years of operation of the well before the acoustic effect. In accordance with predicted flow rates (7.9 tons per day) it could have reached only 3.9 thousand tons, which, due to acoustic effect, provides guaranteed extra oil in the volume of 19.6 thousand tons (25.3 %). Water cut level during acoustic effect remained unchanged – less than 1 %.

Performance values of acoustic method for enhanced oil recovery have an obvious advantage over results gained after stabikator solvent treatment, as well as hexane fraction in combination with nitrilotrimethylphosphonic acid considering maximum and average flow rates, maximum production rate and time for signs of a positive effect (Fig. 10, 11).

First of all, it is necessary to pay attention to longer duration of the effect as compared to other methods, which in the end caused a significant amount of extra oil extracted. Effect from stabikator is shown per one treatment, time for its development may be taken as equal to 167 days, in this case relative effect of acoustic impact will be 331 days longer (198%).

An essential point is that no workover operations were conducted at any wells after the acoustic impact. Therefore, at well 174 of Pikhtovsky field workover

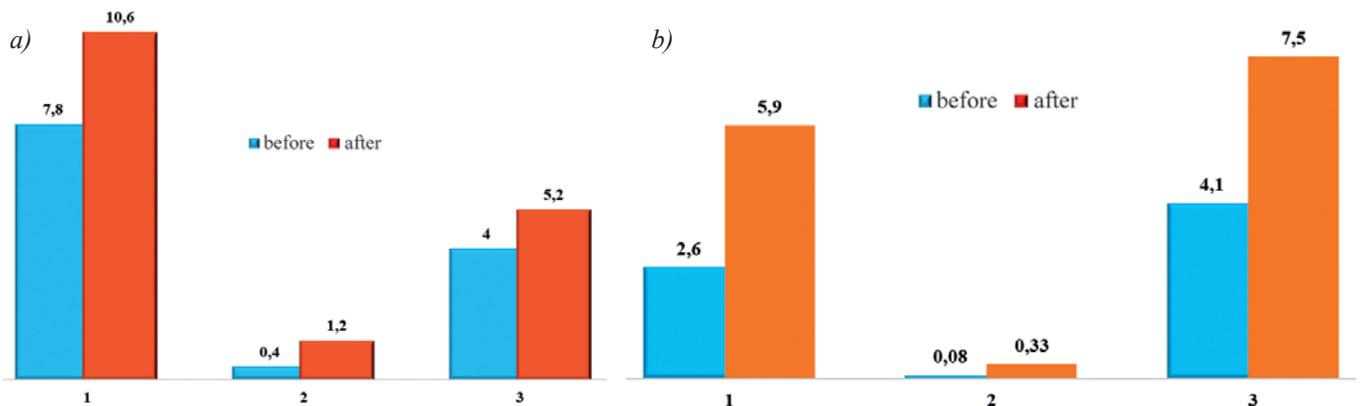


Fig. 7. a) Formation’s working thickness (m), b) Productivity factor (ton/day\*MPa). Legend on Fig. 5

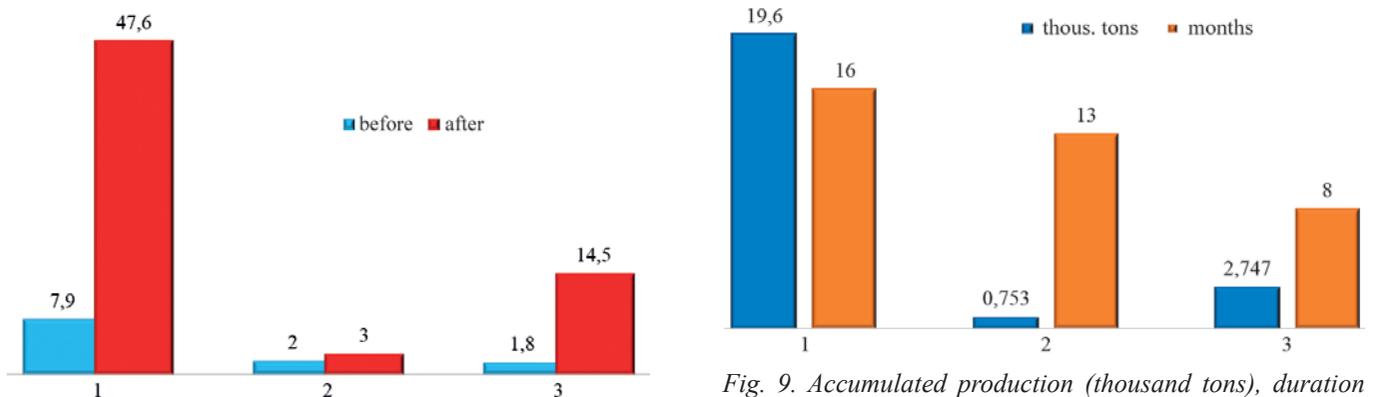


Fig. 8. Changes in average daily flow rate (ton/day). Legend on Fig. 5

Fig. 9. Accumulated production (thousand tons), duration (months). Legend on Fig. 5

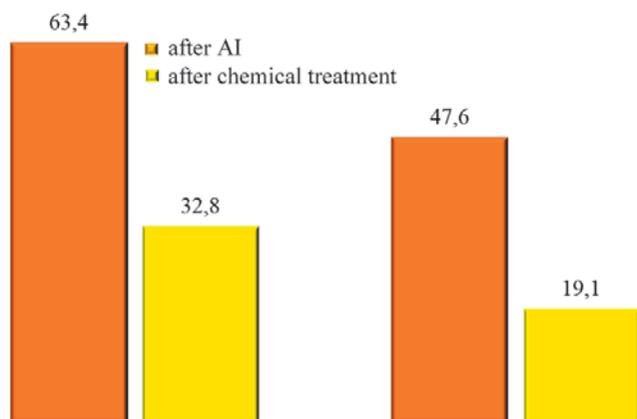


Fig. 10. Maximum flow rate, average flow rate (ton/day)

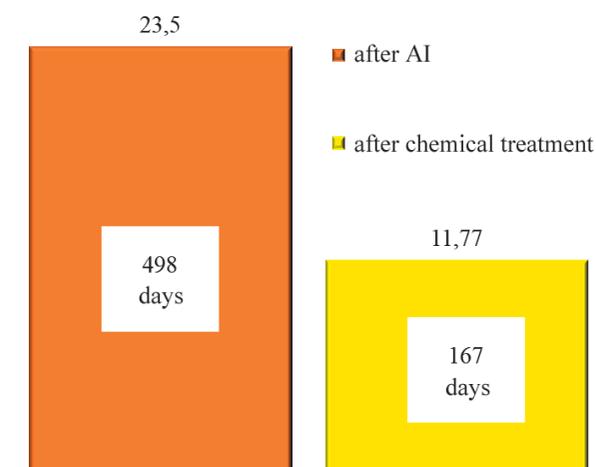


Fig. 11. Extra recovery (thousand tons), duration of the effect (days)

turnaround time amounted to 16.6 months, whereas for well 266 of Olkhovsky field and well 255 of Unvinsky field it will amount to over 13 and 8 months accordingly.

Consequently, at all the three Wells, high-frequency treatments of bottomhole zones in Terrigenous formations applying AAV310 tool equipped with magneto-striction sensors turned out to be successful. Actual and predicted oil recovery data throughout long period after the acoustic effect completely validate conclusions made after hydrodynamic surveys on significant improvement of buttonhole zone and indicate effectiveness of conducted oil recovery enhancement operations.

The hydrodynamic survey method described in this paper is comprehensive in terms of quality and evaluation of efficiency of acoustic impact results, but at the same time it is labor-consuming and expensive for regular use with acoustic impact which is conducted on a small-size tool applying geophysical survey technology. Therefore a control method was developed based on investigations of elastic energy, its parameters and properties depending on the changes in formation's reservoir properties during acoustic effect. Fundamentals of this method lie in the studies of elastic energy's emission in a formation

caused by natural processes and induced by various artificial impacts, including acoustic effect (Dryagin, 2001). Elastic energy emission is a process of elastic waves' radiation in a geologic environment in a wide range of frequencies, from tens of Hertz to ultrasound. Such radiation or seismo-acoustic emission undergoes significant changes in a saturated porous medium subject to an impact from a high-intensity elastic vibrations source. Given that, parameters of such impact may also vary within a wide range – from land vibroseis sources to ultrasonic downhole sources. A peculiarity caused by seismo-acoustic emission, is dependency on reservoir properties of a saturated porous medium under the influence of acoustic impact on a productive formation. Results of oilfield tests of the acoustic impact applying AAV400 tool which merged two functions – radiation of a strong magnetic field and receiving weak emission signals in a well within one technological cycle, enabled to gain new and sufficient information on energy processes in reservoirs and their connection with presence and extraction of oil (Dryagin et al., 2005; Dryagin et al., 2014).

Radiation of acoustic field and receiving signals from seismo-acoustic emission are conducted by units installed in one borehole geophysical tool which may move along the borehole during the survey with a given tool operation algorithm. The acoustic emission energy which emanates during impact was established by computation of energy's spectral density over the entire recorded frequency range – from tens of Hertz to 20 kHz. The data was further processed by Intengraf software. Fig. 12 shows an example of comprehensive analysis of acoustic emission signal in a productive formation BC10 at Tevlinsky-Russkinsky field (West Siberia) during acoustic impact.

Fig. 12a shows diagrams acquired while applying acoustic emission logging technology along with acoustic impact in a well. Logging spectrogram is generated in real time during the tool's movement while measuring natural radiation background of seismo-acoustic emission and then during implementation of the cycle: acoustic impact – measurement of acoustic emission for each point with 0.5 m step. The log shows the curves of acoustic emission's energy signals before and after acoustic impact, as well as differences in energy in percentage relative to the background. Fig. 12b shows acoustic emission signal and its time spectrogram which may also be viewed during logging operations. Fig. 12c shows an example of acoustic emission signal spectrum at 2845 m depth before and after acoustic impact. The spectrum was computed using specialized special software in a sliding window with identification of key frequencies. Similar to core samples, discrete frequencies are clearly established as well as their dynamics during acoustic impact.

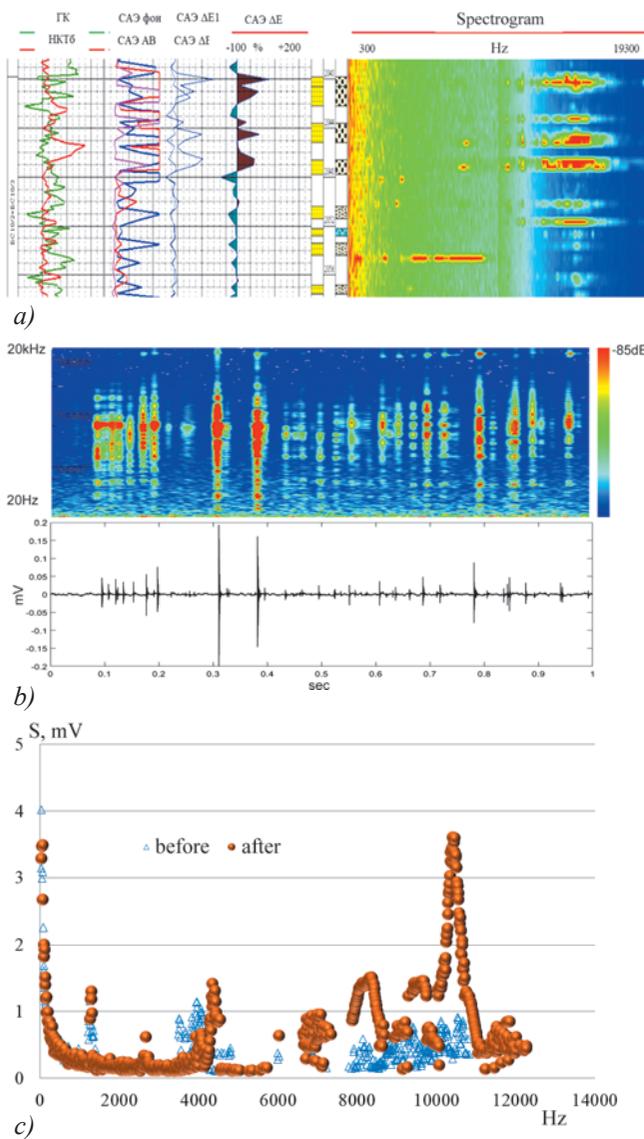


Fig. 12. Analysis of the emission during acoustic impact

Non-uniformity of reservoir properties along the well section is reflected in the curves showing the energy signal of acoustic emission which is measured in percentage relative to a background value, as well as in the form of a logging spectrogram. Since seismo-acoustic emission logging was performed before perforation, the emission induced by the impact only shows potentially oil-saturated intervals in the formation. The lower interval at the bottom of the formation (2846-2847) also shows positive acoustic emission dynamics, but it was not included in the perforation jobs, probably due to fears of its flooding. Probably it should have been included in development activities which could have increased the well's production rate. Nonetheless the well perforated in the mentioned interval yielded flow rate of 48 tons per day, against water cut of 2% (Table 2).

On average, increase in the seismo-acoustic emission signal after acoustic impact is several tens percent in a formation saturated with oil relative to background value. At the same time, individual events of acoustic emission in the form of single impacts of emission sources occur randomly and have typical parameters of signal pulse with finite duration of a certain shape. At the same time, there is presence of dominant frequencies with a certain maximum energy value and pulse-modulated frequency.

According to geological-geophysical data acquired in oilfield tests for oil flow from these formations and comparison with seismo-acoustic emission logging, a connection has been established between emission parameters and the type of its reservoir. Productivity is established through porous and fractured types of reservoirs which are in various ways established due to dominant frequencies and their energy's dynamics

Field	Interval	Conclusion about saturation		Results		Diagrams well logging/ seismo-acoustic emission logging
		Formation	Well	Flow rate/ $K_{water}$		
Tevlinsky-Russkinsky	2838-2858 m	Oil	Oil	48 t/s	2%	
	BS10/2 -BS10/3					
No.XXX5	2840-2845 m					
Tevlinsky-Russkinsky	2518-2538 m	Oil	Oil	41 t/s	2%	
	BS10/2 -BS10/3					
No.XXX7	2518-2520 m					
Druzhnoe	2941-2976 m	Oil	Water	54 t/s	97%	
	YuS1					
	No.XXX6					
	+ HF					

Table 2

after acoustic impact. Porous reservoirs with 2-12 mD permeability have dominant frequencies (6-9 kHz) and 30-40% growth of seismo-acoustic emission energy relative to background values. During inflow tests in two such wells they yielded flow rate of approximately 40 tons per day of oil with water cut not exceeding 2% (Table 2). Similar tests in reservoirs with permeability of 221-444 mD yielded 40 tons per day, with the following acoustic emission parameters: dominant frequency – 10-12 kHz, growth of acoustic emission energy – 180% relative to background values. These reservoirs are characterized by appearance of the second dominant frequencies range in the 2-4 kHz domain with dynamics 2-3 times less than previous frequency. Activity of emission along the formation changes abruptly and non-uniformly, which indicates a vast non-uniformity of the reservoir-bed in terms of its filtering and capacitance properties.

Similar results were gained at well XXX7, which also penetrated formation BC10 at Tevlinsky-Russkinsky field (Table 2). Fig. 13 shows data on emission energy as well as on permeability and electrical conductivity of the formation which was acquired during open hole logging. The setup in this well is close to that in the previous well. Upper part of the formation in the 2518-2522 m interval shows higher resistivity, permeability and emission energy. Below the 2522 m depth emission activity caused by the impact abruptly declines which indicates formation's flooding, this factor is also matched by electrical resistivity. With that, according to final logging data, permeability is abnormally high in the 2525-2528 m interval – approximately 380 mD, however acoustic emission methods and electrical conductivity point at its water saturation. Perforation was conducted in the 2518-2520 m interval, oil inflow amounted to 41 tons per day with 2% water cut.

A water-saturated formation is shown as a case study of well XXX6 at Druzhnoe field in West Siberia. Here we can trace negative dynamics of induced acoustic emission after acoustic impact which is reflected on

logging curves (Table 2). Testing results showed fluid inflow with 54 tons/day rate and 97% water cut. This well underwent hydraulic fracturing which contributed to a larger flow rate, however not taking into account the current saturation of the formation led to almost complete water flooding.

Application of the method in Carbonate reservoirs is shown for Alibekmola field, where oil- and gas-bearing capacity is associated with pre-salt Carboniferous deposits and two productive beds KT-I and KT-II confined to them and split by an inter-carbonate bed of rocks.

In order to study current oil saturation and to enhance oil extraction from productive formations at the field, they applied seismo-acoustic emission logging along with simultaneous impact on the bottomhole zone in the well.

The works applying seismo-acoustic emission technology conducted in well 54 at Alibekmola field, were carried out in the 3158-3378 m interval which matches with an oil pool confined to lower Carbonate bed KT-II with deposits of Upper Viséan-Kashirian age, and lithologically consists of mainly limestone with interlayers of greenish-gray mudstone.

The interval investigated in the well refers to a productive formation KT-II-II-4, in which oil saturation was established with Well Logging data, with that effective penetrated thickness is 18.9 m, whereas effective water-saturated thickness is up to 33.4 m. Conventionally water-oil contact for this block was accepted at absolute elevation -3324.8 m. As of the date of seismo-acoustic emission surveys which were conducted twice in 2003 with a 2 months interval, oil recovery parameters over major intervals are given in Table 3.

General characteristics of the well's operation throughout this period were established as non-stable on 7 mm choke with most intensively working intervals being 3262.2-3268 m, 3210.1-3216 m and 3160-3163.1 m. On the 9 mm choke, the well's working mode became established due to operation of lower intervals, with that fluid yield re-distributed over working intervals. For example, the 3280.9-3303.3 m interval became operational with 87 m<sup>3</sup>/day flow rate which equaled to 36% of total inflow. The 11 mm choke also saw intensified operation of lower intervals, but in addition there was a sharp growth of flow rate from the 3210.1-3216 m interval: 139.57 m<sup>3</sup>/day.

After the acoustic impact, acoustic emission increased in working intervals in proportion to the growth of fluid inflow in them. At the same time, emission signal exists in the intervals before the acoustic impact but then changes its shape and location. The well's performance significantly improved right during the acoustic impact. The impact was applied

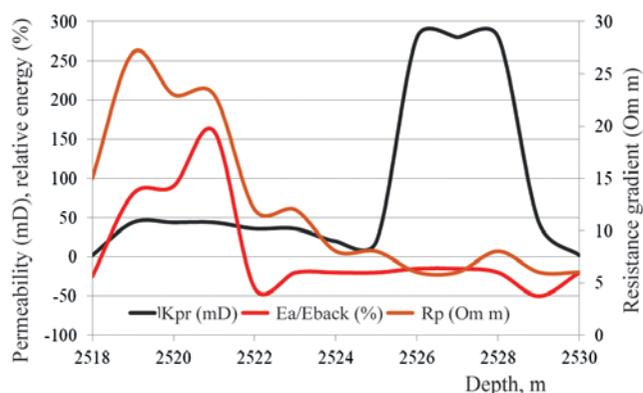


Fig. 13. Well Logging and seismo-acoustic emission energy

Perforated interval, m	Flow rate			Dynamics of seismo-acoustic emission after AI, % of background		Operational intervals, m	
	(m <sup>3</sup> /day) -- (% of total)						
	with choke			07.04.2003	01.06.2003	07.04.2003	01.06.2003
3210-3216	32.8 -- 24.5%	18 -- 7.6%	139.6 -- 38.5%	18	-140	3212,5-3214	3208-3218
3233-3235	0	0	0	-17	-20	3223,5-3234	3232-3235
3262-3268	29.8 -- 22.3%	18.1--	4.4 --	-15	-10	3261-3262	3260-3264
		7.6%	1.2%			-11	-60
3280-3306	1.6 --	87.2 --	82.2 --	11,6	2	3280-3282	3280-3306
	1.2%	36.5%	22.7%	10,8		3284-3286	
					-10		3292-3294
				4,9		3299-3300	
3320-3326	18.2 --	25.3 --	12.8 --	-26	4,3	3320-3322	3320-3322
	13.6%	10.6%	3.5%				

Table 3

consecutively over all perforation intervals starting from the top, and the wellhead pressure grew from 4 mPa to 9 mPa by the time the work was completed in the lower perforation intervals. Similar to testing, increase in the coke size led to capture of water from formations which was indicated by an intensive water kick, leading to extinguishing of associated gas flare. Fig. 14 shows an acoustic emission logging spectrogram at the time of acoustic impact. The acoustic impact itself consisted in radiation by acoustic power field lasting not

less than 2 minutes per 1 meter of formation’s interval. With that, even the intervals outside of perforation activities were subjected to impact.

Fig. 15 shows acoustic emission spectra before and after acoustic impact at the points where the tool stopped, at the same time the 3264 m recording point is inside the perforation interval and the 3327 m point is within a non-perforated interval. Since the emission signal outside of the perforation interval has the same large dynamics as in the productive perforation interval, we can say that this interval also has an oil recovery potential.

Non-linear properties of the Carbonate medium found their reflection as discrete frequencies similar to those acquired for Terrigenous reservoirs with core samples and Well Logging data.

Therefore, excitation of high-intensity elastic waves in a productive formation and recording of emission waves provide acquisition of reliable information on current oil saturation of a productive formation in a non-perforated well and may provide recommendations on selection of a perforation interval and stimulate oil flow from the formation.

### Conclusions

Elastic energy of a reservoir-bed saturated with oil and gas is a reliable informative parameter of its production capacity.

Induced acoustic emission logging makes it possible to identify reservoirs in Terrigenous and Carbonate sediments, to clarify the geologic structure of deposits.

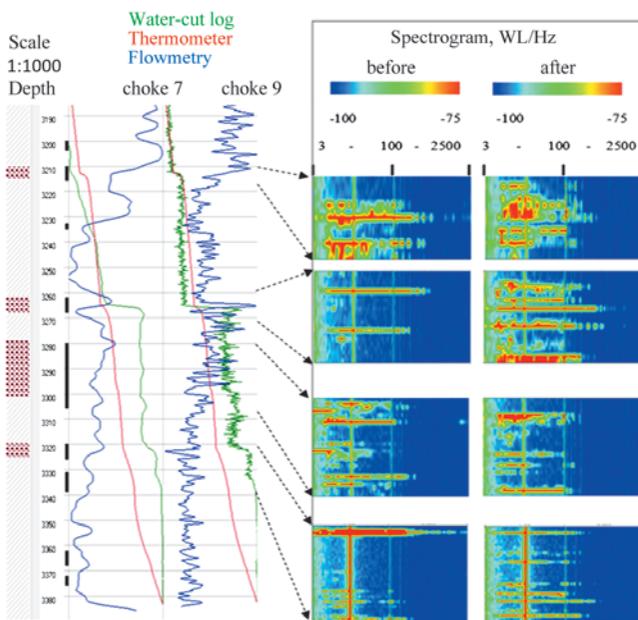


Fig. 14. Alibecmola field, well No. 54

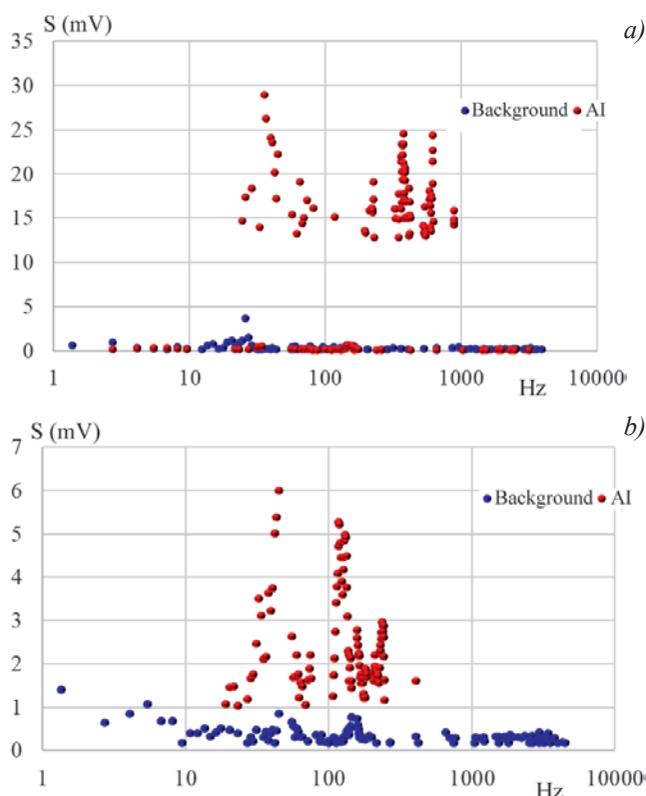


Fig. 15. Acoustic emission spectra during acoustic impact in two points of a surveyed interval. a) acoustic emission spectrum at 3264 m depth, b) acoustic emission spectrum at 3327 m. Background – background record of acoustic emission before acoustic impact, AI – acoustic emission after the impact

The technology enables to reconstruct oil and gas reservoirs, to establish the type of fluid saturation and to provide evaluation of reservoir's capacitance parameters in the conditions of high compartmentalization of the reservoir and non-uniformity in terms of permeability.

The studied technological solutions will be able to provide necessary information to select an optimum development plan and to increase the oil recovery factor.

This technology is realized with a small-size probe 43 mm in diameter and is implemented within one running operation using the MSAE 100 hardware and software package developed by Intensonic.

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## SHORT COMMUNICATION

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## An example of practical application of information on fracturing according to the well logging data complex and high-tech methods

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**Abstract.** In the article the issue of investigation by logging methods of reservoirs with natural fracturing is considered. A special case of revealing the reason for fast watering of productive layers with the help of a logging data complex and high-tech methods, such as: cross-dipole acoustic logging, acoustic scanner, electric micro-imager is considered. Scanners allow us to get an image of the inner surface of the well wall in order to reveal fractures. Measurement of the propagation characteristics of acoustic waves is used to detect fractures. Complex interpretation led to the conclusion that the watering is due to the presence of sub-vertical fractures associated with the underlying aquifers.

**Keywords:** fracture, microscanner, watering

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There are several approaches to identification and investigation of reservoirs with natural fracturing. Out of these approaches, the following deserve closer attention (Dobrynin et al, 2004):

- lost circulation and growth of ROP during drilling are the main indicators that drilling is going on in a fractured and porous medium;
- fractures and core solution channels provide direct information on the nature of reservoir's porosity. If actual flow rates of a formation are several times higher than those estimated with core data, then we should suspect presence of natural fractures in such a formation not observed on core samples. A low core delivery rate – less than 50% – also presumes presence of a strongly fractured carbonate rock in the core sampling interval;
- logging tools are designed in such a way that their readings are variously affected by different features of a borehole and a section. Well Logging methods based on measurements of acoustic waves propagation characteristics are used for identification of fractures. Caliper logging data, density logging and electrical logging data in certain circumstances may be useful for identification of fracture zones;
- pressure build-up curve analysis;
- vertical fractures in a non-deviated hole may be

identified as high-amplitude anomalies intersecting other bedding planes;

- fractures and solution channels are discovered with methods for direct or indirect imaging of borehole walls applying a borehole imager;
- abnormally high production rate is typical of naturally fractured formations;
- a significant growth of a Well's productivity after hydrochloric acid inflow stimulation is a reliable indication of a formation with natural fracturing. Acid treatment is conducted in order to expand fractures and channels;
- due to high permeability of fractures, pressure's horizontal gradient in a fractured formation is generally not high, both near the well and over the entire formation.

Table 1 shows the methods, and their capabilities and limitations in identification of fractures. It is obvious that the most effective instruments for assessment of fractures are acoustic and electrical micro imagers.

The oilfields of TPP "TatRITEKneft" of Nurlat Group showed flooding of productive horizons during development. In order to establish causes of fast flooding, it was decided to apply an extended set of Well Logging methods, including high-tech investigations. Fracture studies in Mid and Lower Carboniferous deposits were conducted in two wells: No. 1426 (crestal) and No. 1429 (flank). Their location is shown on Fig. 1 of a structure map for top Tournaisian stage. The entire completed set of Well Logging methods was analyzed, including electrical micro imager (MCI), cross-dipole acoustic log

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	Core	Electrical Formation Imagers (FMS/FMI/MCI)	Acoustic Borehole Imager	Litho-Density Log	Lamb-Stoneley Wave	Lost Circulation
What is identified?	Local fracture porosity	Mud penetrating fractures	Contrasting acoustic properties	Density of hard mud particles penetrating the fractures	Stoneley wave energy reflected by fractures	Loss of circulation from borehole into formation through fractures
How narrow are the fractures to be identified?	Approximately several micro meters	Approximately several micro meters in case of sufficient conductivity contrast	1 mm	5 mm	1 mm	0.2 mm
Man-made fractures mistaken for natural permeable fractures	Fracture porosity. Man-made fractures.	Fracture porosity. Man-made fractures. Formation damaged while drilling	Fracture porosity. Man-made fractures. Interlayers with high impedance values and part of healed fractures	Fracture porosity. Formation damaged while drilling. Salinity.	Boundaries of cavern	No
Survey depth	Core diameter	10 mm	3 mm	100 mm	Less than 1.8 m	Mud penetration radius is >1 m
Can data from this method be used to establish fracture's dip angle and bedding plane angle?	Yes	Yes	Yes	No	No	No
Mud limitations	No	Only water-based mud	Mud density must be less than 1.68 gr/cm <sup>3</sup>	Mud density must be 1.2 gr/cm <sup>3</sup>	No	No
Remarks	No core delivery from highly fractured «corrugated zones»	Hard to differentiate fractures with high and low permeability	Hard to differentiate fractures with high and low permeability	No	Fractures clogged with mud's hard particles are often not identified	Provides information on the level of formation damage and requirements to its treatment

Table 1. Brief characteristics of natural fractures investigation methods (according to Mukhamadiev et al, 2014)

(MPAL) and acoustic scanner (CAC) in order to identify fractures which contribute to Well flooding.

Figures 2, 3 show interpreted data from the extended Well Logging set of methods. The second track after depth column on Figure 2 shows Gamma-Ray curve, Caliper Log and Neutron Gamma-Ray Log, Gamma-Gamma Density Log curves; the third track shows Nuclear Magnetic Log; the fourth one – electrical metering; the fifth track shows porosity and oil saturation coefficients; the following columns show fractured intervals identified due to various Well

Logging techniques, including anisotropic intervals identified after Cross-Dipole Acoustic Logging (tracks 8-10). The right-hand side of the Figure shows Cement Bond Log data, string contact, Variable Density Log (string bond and rock bond). Identified fractured intervals are confirmed by deterioration of the casing string's cementing quality identified during another acoustic survey in a cased hole (Fig. 2b), as well as by further fast flooding of productive reservoirs.

Well 1426 in the 951.0-1035.0 m interval (Vereiskian-Bashkirian) after electrical micro imager identified 13

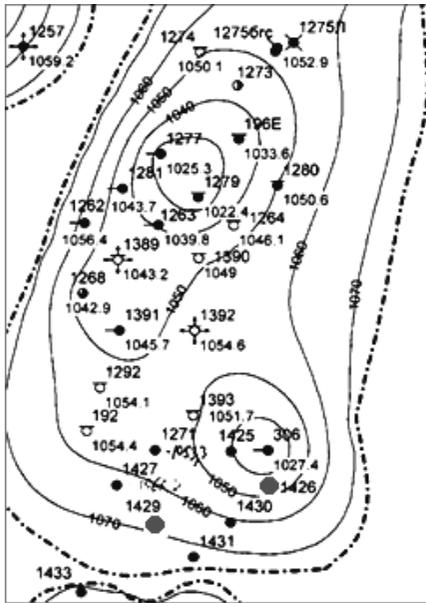


Fig. 1. Structure map for top Tournaisian stage

healed fractures, 8 partially-healed fractures and 3 open fractures. The 1196.5-1295 m interval in total showed 20 healed fractures, 14 partially-healed and 4 conductive fractures. The fracture dip angle was predominantly 45.2-74°.

According to acoustic logging data, in well 1429 five healed fractures were identified in the 1188.6-1222.4 m interval. The fracture dip angles vary within 65.8-71°, the dip azimuth is within 91-115.6° range (south-east being the main dip direction).

An example of a fractured interval as per electrical micro imager data is shown on Figure 4.

Well 1429 located at the flank of the structure, according to high-tech methods identified much less fracture intervals. Fast flooding is most likely to be caused by presence of sub-vertical fractures associated with underlying aquifers. The cause of Well flooding is in presence of natural fracturing of rocks.

Therefore, high-tech methods identified a reason of fast flooding which is associated with natural fracturing of sub-vertical trend.

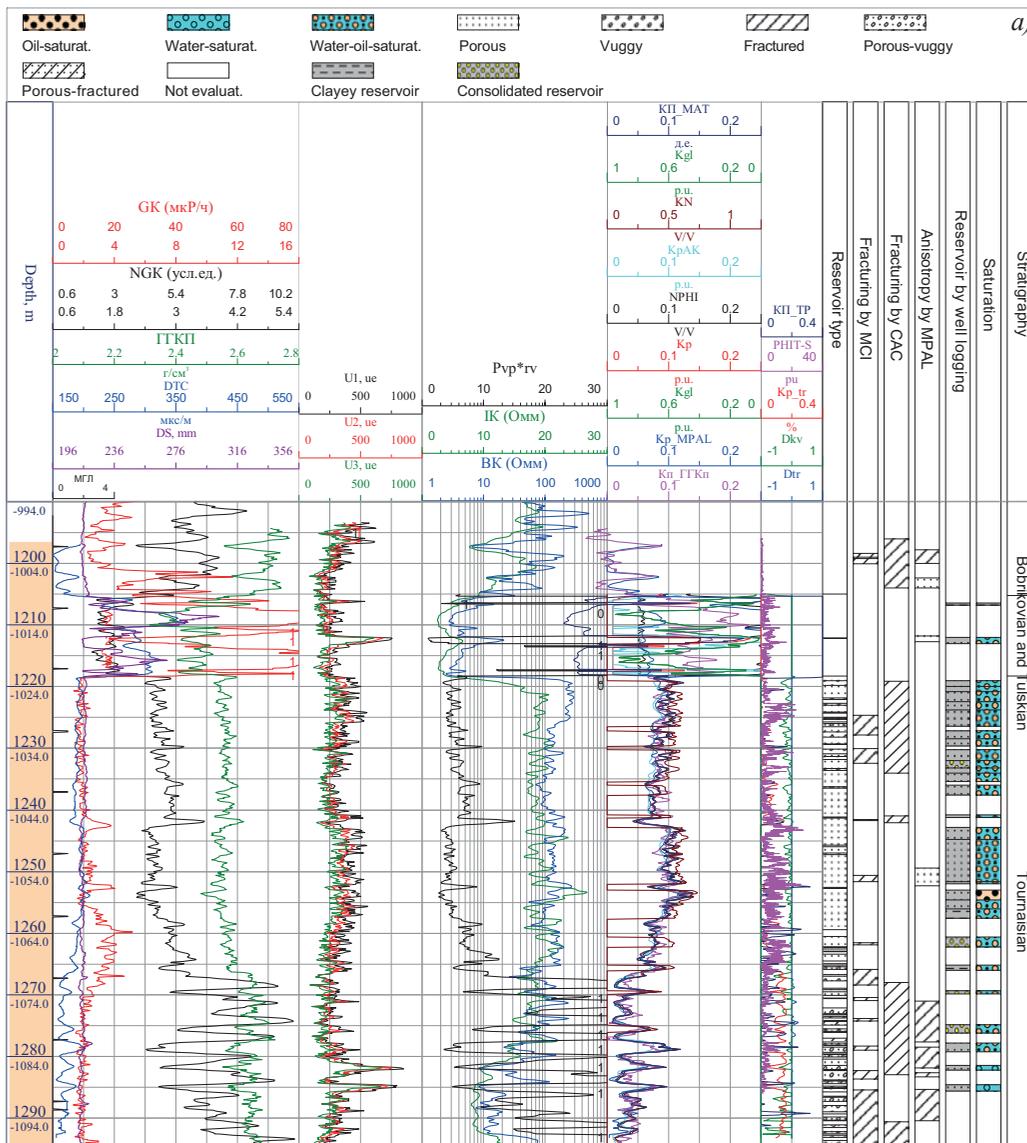


Fig. 2. Analysis of fracturing for well 1426 in Lower Carboniferous deposits: a) open hole, b) cased hole

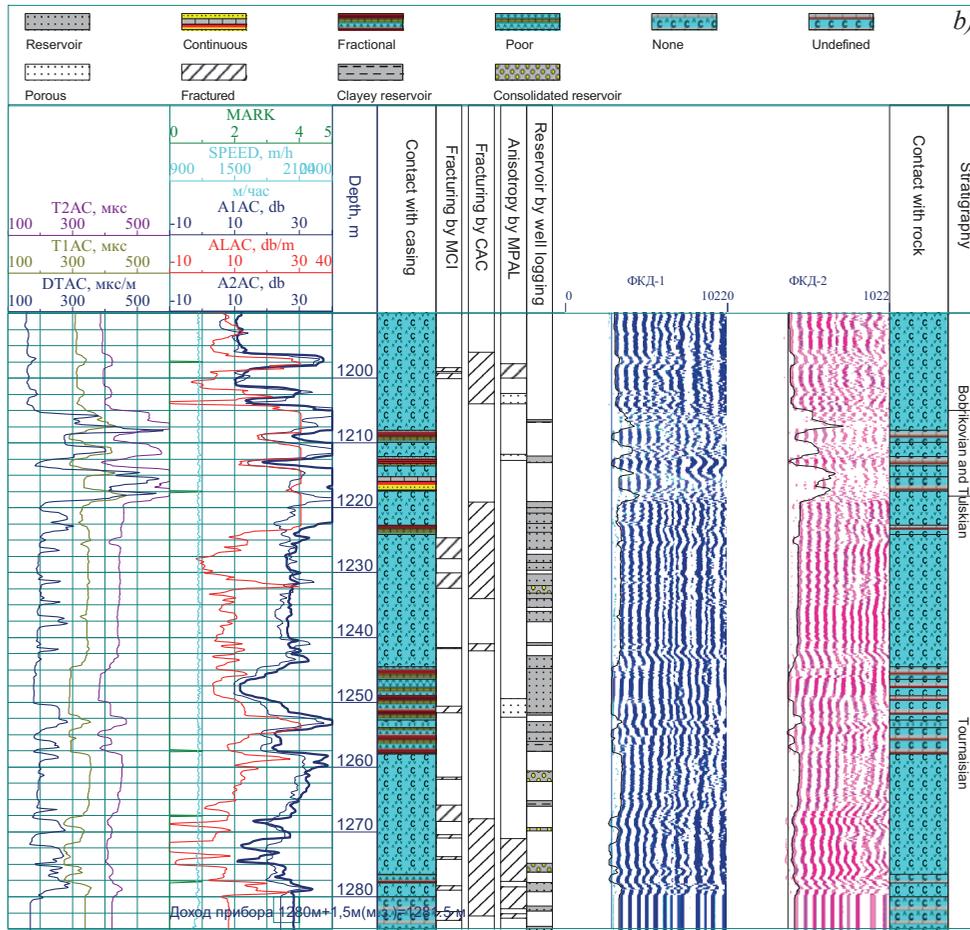


Fig. 2. Analysis of fracturing for well 1426 in Lower Carboniferous deposits: a) open hole, b) cased hole

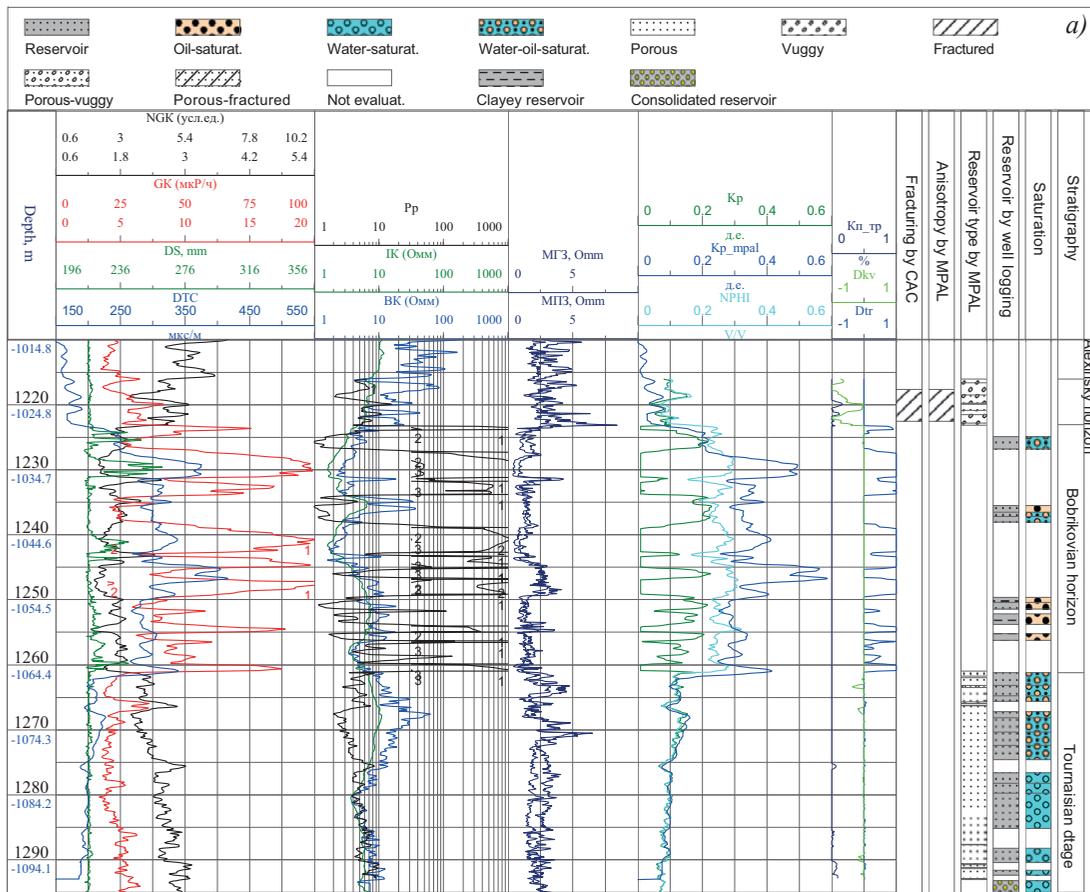


Fig. 3. Analysis of fracturing for well 1429 in Lower Carboniferous deposits: a) open hole, b) cased hole

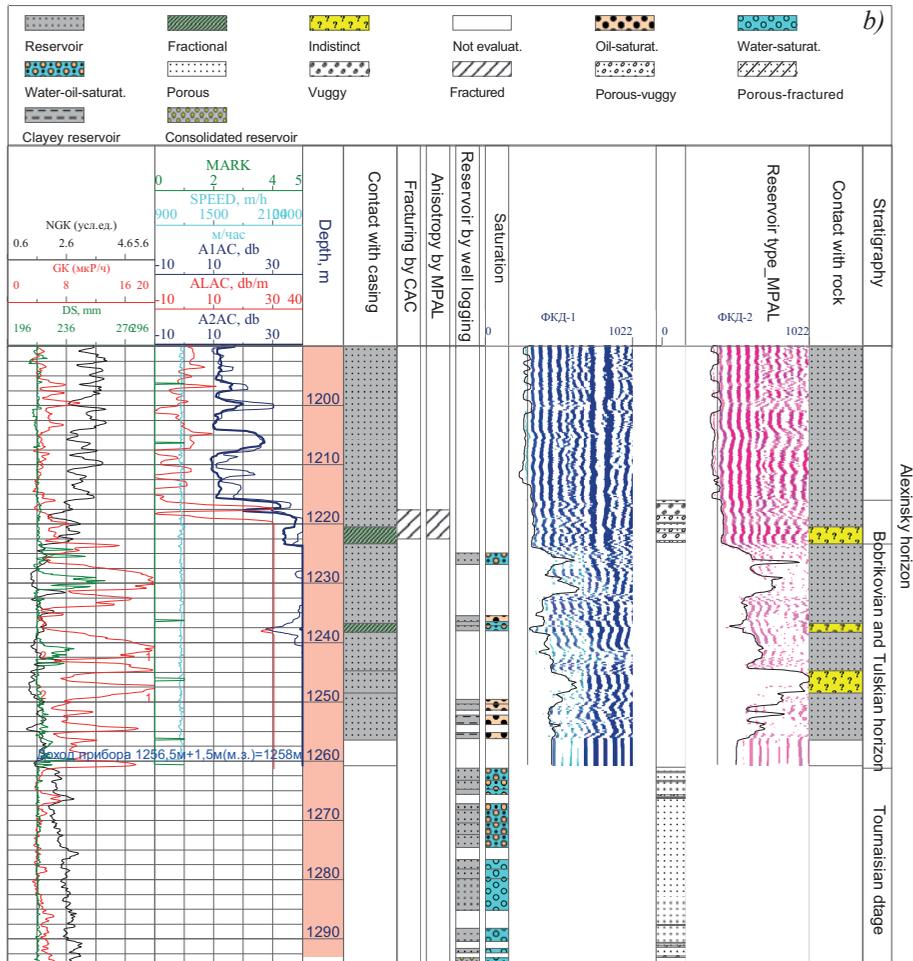


Fig. 3. Analysis of fracturing for well 1429 in Lower Carboniferous deposits: a) open hole, b) cased hole

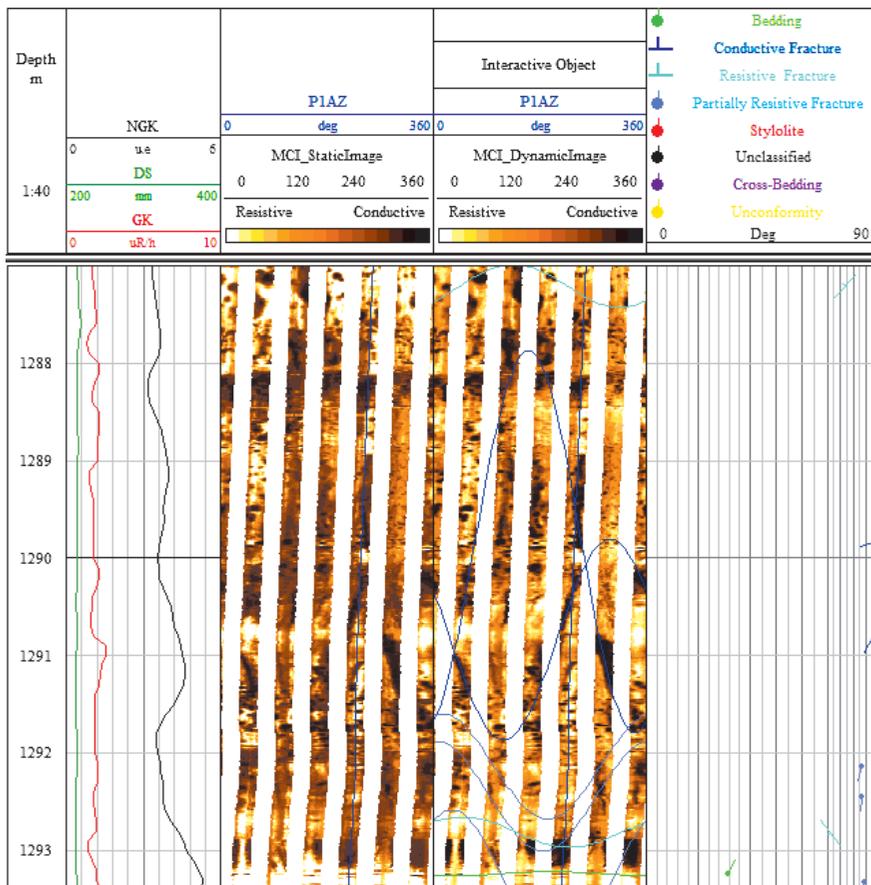


Fig. 4. Example of a fractured area according to electrical micro imager data

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# The possibilities of well logging data methods for studying fracturing

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**Abstract.** This article covers the main methods of geophysical well studies aimed at studying fractured zones. Examples of the results of a quantitative evaluation of fracture parameters and examples of their use when working with seismic data and constructing hydrodynamic models are given. The emphasis is made on the need for a cross-cutting technology to study the type of pore space from seismic data, geological and technological studies, core, geophysical studies of wells, field geophysical studies, hydrodynamic studies.

**Keywords:** fractures, reservoir, well logging, field geophysical studies, permeability, watering

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Over a 25-year history of the Pomor-GERS LLC, wealth of experience has been gained in the field of geophysical well logging in different regions: Timan-Pechora petroleum and gas province, Volga-Ural petroleum and gas province, Siberia, Kazakhstan, Uzbekistan, etc. The great scope of our work is associated with extremely complex objects for which standard techniques are not suitable. Each region has its own characteristics, but issues such as pore volume and tectonics are acute in all regions. During these years, the company's specialists have developed techniques for studying non-standard reservoirs with a focus on the type of pore volume.

Our techniques have been tested at more than 20 fields, and at more than 500 wells. We have gone from a selection of fracture zones at a qualitative level to the quantitative geophysical assessment of such complex parameters as density, opening, fracture capacity, their permeability, etc.

The main idea that we are trying to communicate to subsoil users is as follows: what matters are not separate, even very advanced and expensive technologies, but systematic works on studying the type of pore volume. There is a need for end-to-end technology to verify and complement regional seismic, geological modelling, etc., which is only possible after well drilling.

The main stages of obtaining information that should not "live" independently, but constantly overlap and

complement each other: **geotechnical survey, sludge, core, open-hole well logging, well testing, geotechnical survey + field-geophysical research, closed hole well logging, field operations results.**

A constantly updated document is required in which the presence or absence of fractures, caverns should be noted from the first days of work. Perhaps in some cases it will sound even odd: "we looked for cracks and caverns using methods (seismic, geotechnical survey, open-hole well logging, field-geophysical research, etc.) – are absent". This is important both for the possibility of obtaining the inflow of the expected hydrocarbons, and for the prevention of advanced flooding. The fractures problem of is also of ecological importance, since disposal of wastes may lead to regrettable consequences.

When studying rocks, especially carbonate rocks, one should proceed from the assumption that there are always fractures (or there were). It is important to know the genesis of fractures, what they are and how many. Photos of a core with various type of fractures are given in Fig. 1-5.

In this article we will focus only on some points in the chain of studies based on the methods of geophysical exploration of wells, which allow us to move to a new level of areal and regional studies that are crucial for building a hydrodynamic model.

## High-resolution scanning methods

An important group of relatively new methods for the study of complex sections is high-resolution scanning methods, both electrical and acoustic. The previous research methods included the use of tiltmeters that have been used for a long time, but due to the limitation or lack of computer technology, has not been properly

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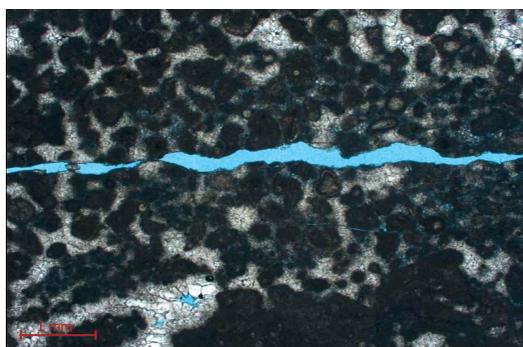


Fig. 1. Microfractures (thin section)

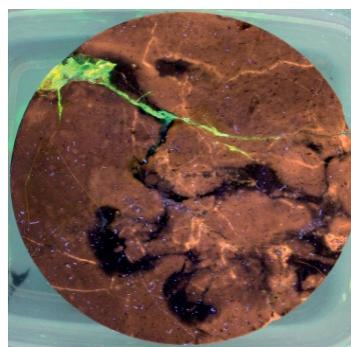


Fig. 2. Caverns along the fractures, (with bitumen)



Fig. 3. Meso-fractures



Fig. 4. Macro-fractures



Fig. 5. Tectonic fractures (with calcite)

developed. Modern equipment production technologies, and most importantly computer imaging technologies and possibility of multivariate processing of the received data, have given a breakthrough in the development of this area of well logging. An important advantage of these methods is the ability to visually and clearly not only for geophysicists to correlate an image of the physical properties of the rock with a real rock. Examples of such visualization are given below (Fig. 6, 7).

The possibilities of the method are not limited to the photographic display of the section.

For the analysis of the structure of the reservoir as a whole and fracturing on the scale of the field, statistical processing of the results of scanning methods is of great importance, which allows to divide the groups of fractures in azimuth and inclination angle. Fracture opening analysis, the capacity of the caverns along the fractures for each system, gives an insight into the hydrodynamic characteristics of the studied part of the section at initial stages of the investigation.

The following are examples of scanner processing results (Fig. 8), an example of construction of the map of fracture distribution over the area (Fig. 9) and an example of a comprehensive analysis of seismic data and well logging (Fig. 10).

The full-waveform logging has gained considerable

prominence in the study of fracturing. Recently, new generation devices are used extensively, both domestically produced (AVAK tool), and proposed by Western service companies (DSI, XMAC, SonicScanner, etc.). The use of such devices provides a number of important advantages in comparison with simpler devices of the previous generation:

- Reliable separate recording of waves of different types (S and P waves, and so-called Lamb-Stoneley waves);
- High quality of recording of the amplitude parameters of all waves;
- Anisotropy recording with a cross-dipole sensor.

This provides new opportunities for studying the fractures parameters (fracture capacity, opening, quantity of fractures per meter (fracture density), permeability, spatial orientation) (Fig. 11-14).

One of the major parameters in the study of rocks is permeability. It is extremely important to separate the permeability associated with the traditional granular reservoir and the permeability due to the fracture system. The main method for determining the permeability is acoustic logging, but on condition that the Stoneley wave is obtained from the wavetrain. It should be borne in mind that the appearance of the Stoneley wave depends not only on the properties of the rock, but also

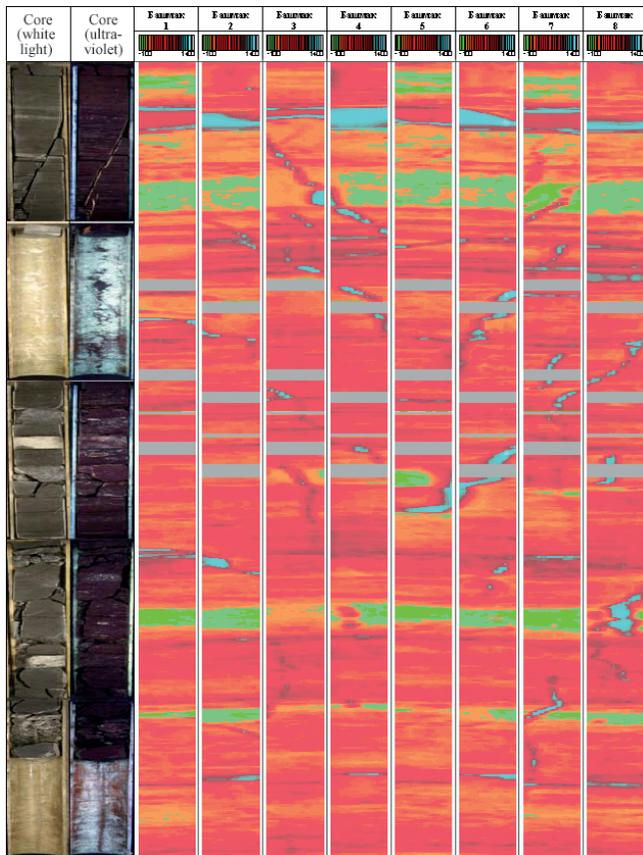


Fig. 6. Photo of core and processing of FMI primary data (“POMOR-GERS”) for further analysis with a high evidence base

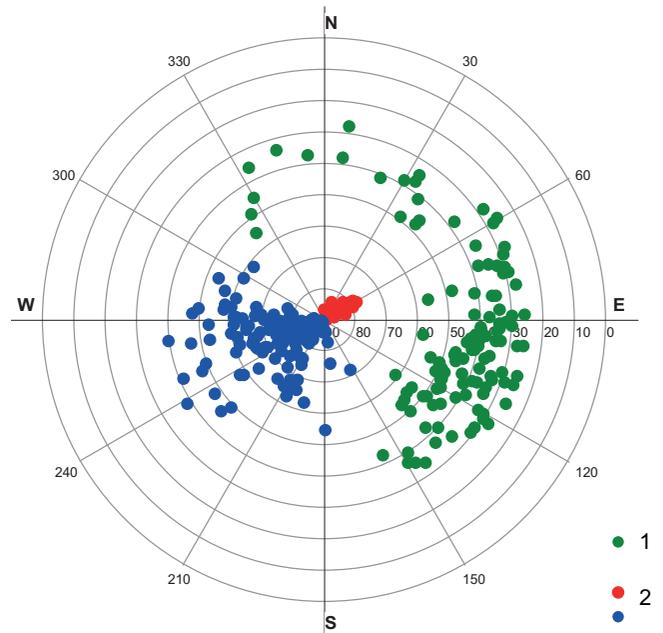


Fig. 8. An example of determining the occurrence of fractures and fracture typing according to the occurrence peculiarities: 1 – a group of sub-vertical fractures, 2 – a group of inclined diagonal fractures with transverse strike azimuths

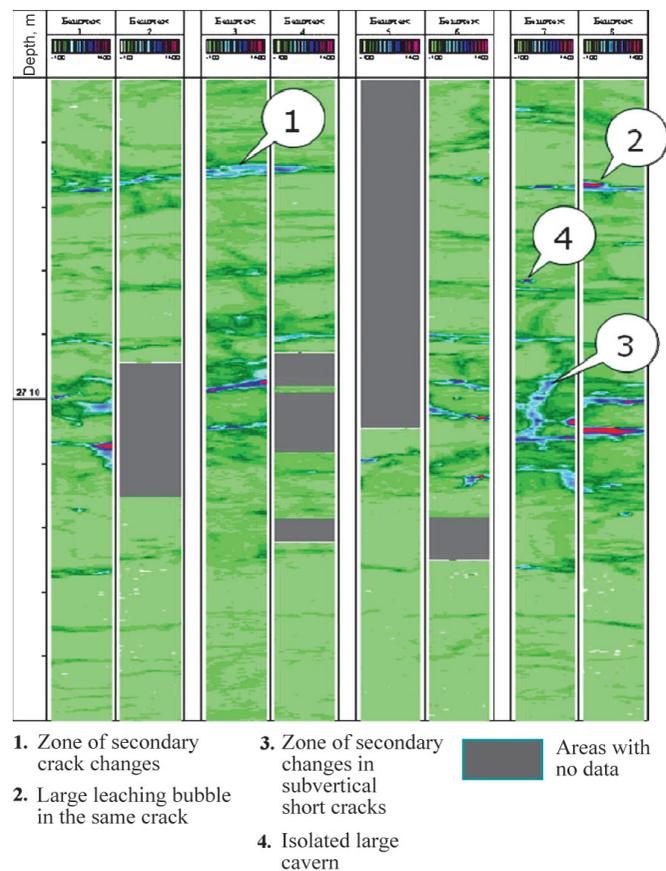


Fig. 7. Selection of objects on microimages

on the conditions of logging, since it is affected by the mud composition, the composition of the fluid in the near-wellbore area, the cavern porosity of the wellbore. It should not be overlooked that one of the tasks in the drilling process is to prevent drilling mud filtration into the formation, while sometimes mechanical impurities, gelling additives are used, which greatly changes the properties of the near-well area, i.e. changes the permeability and propagation conditions of acoustic waves. Of course, there are limitations, but this is the only well logging method that has a direct correlation with permeability.

Figure 13 provides further options for calculating the permeability by different techniques:

- traditional permeability calculation depending on porosity, i.e. this is permeability, associated mainly with traditional granular reservoir (increase in porosity – increase in permeability);
- permeability, determined by the Stoneley wave, which is significantly higher than permeability 1, and in the top of the section has the highest permeability, which should be attributed to the fracture permeability, or vuggy-fractured system (in this area the total porosity of the rock is less than 5%);
- differential permeability, determined in the process of testing the object according to the field-geophysical and hydrodynamic research (methodology developed in “POMOR-GERS”).

Figure 14 gives an example of determining the permeability of sediments with the absence rocks with a porosity of more than 5%. The inflow was only in

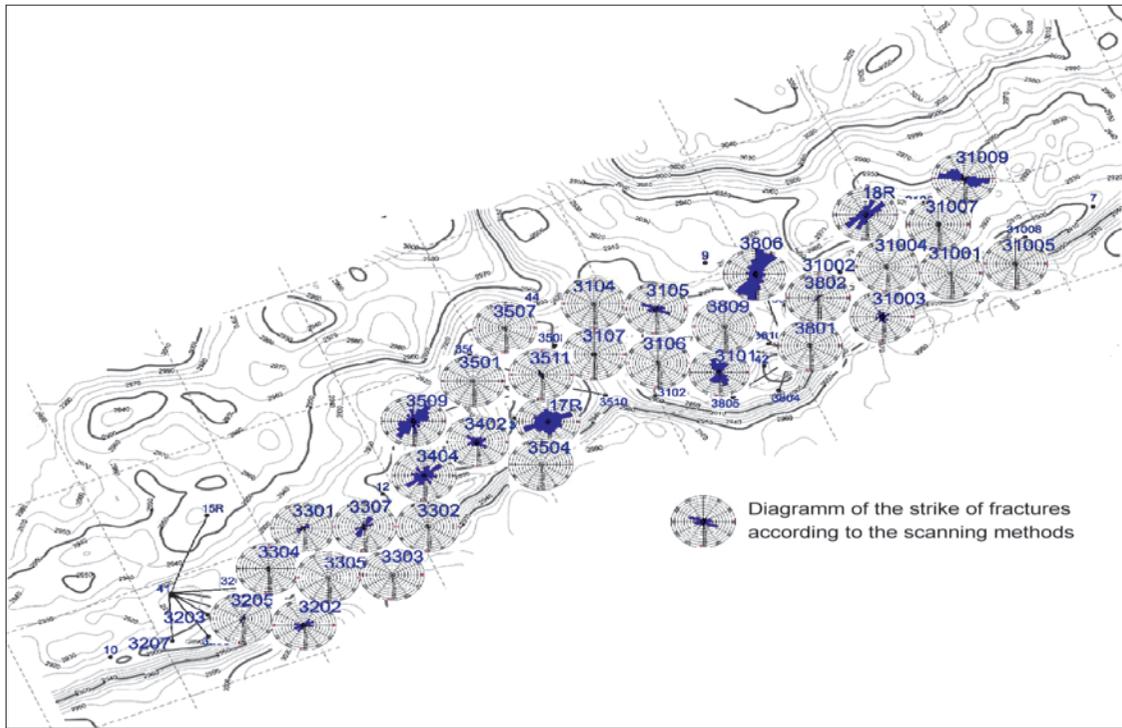


Fig. 9. Evaluation of the dominant direction of the strike of fractures in the studied reservoir along the horizontal

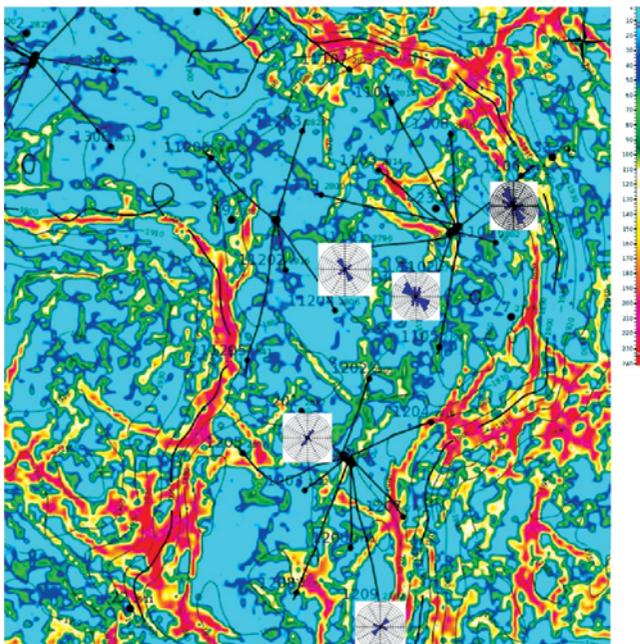


Fig. 10. Azimuths of the strike of fractures against the background of filtered coherence (PetroTrace Global LLC). Full-wave acoustic logging (capabilities)

the intervals where, according to the acoustics data, the cavern and fracture capacity was determined, and where an increase in permeability was noted above the boundary value for the Stoneley wave.

Figures 11, 12 show examples of calculation of fracture porosity (capacity). Given the many restrictions that all well logging methods have, the question arises about the reliability of the quantitative evaluation of this parameter, which is determined by hundredths of a percent. It is a complex issue, and it is difficult to find

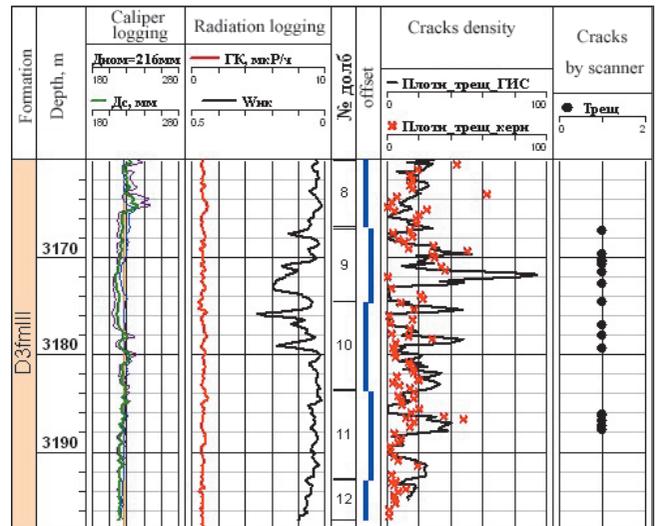


Fig. 11. Comparison of fracture density, defined according to the sonic log data and on a core column

an effective response to it. Of course, it is an essential parameter, and quantitative estimate is important when calculating hydrocarbon reserves associated only with fractures. However, this option is extremely rare, and against the background of the granular and even cavernous capacity, the fracture capacity makes little difference. For the bulk of the studied fields, the very fact of the presence of such a capacity is important, since it is this capacity that will control filtration flows, and the possibility of differentiating this capacity at a quantitative level allows this parameter to be embedded in a hydrodynamic model.

Below are distribution maps of fracture capacity in two fields. On one of the maps, a detailed gradation

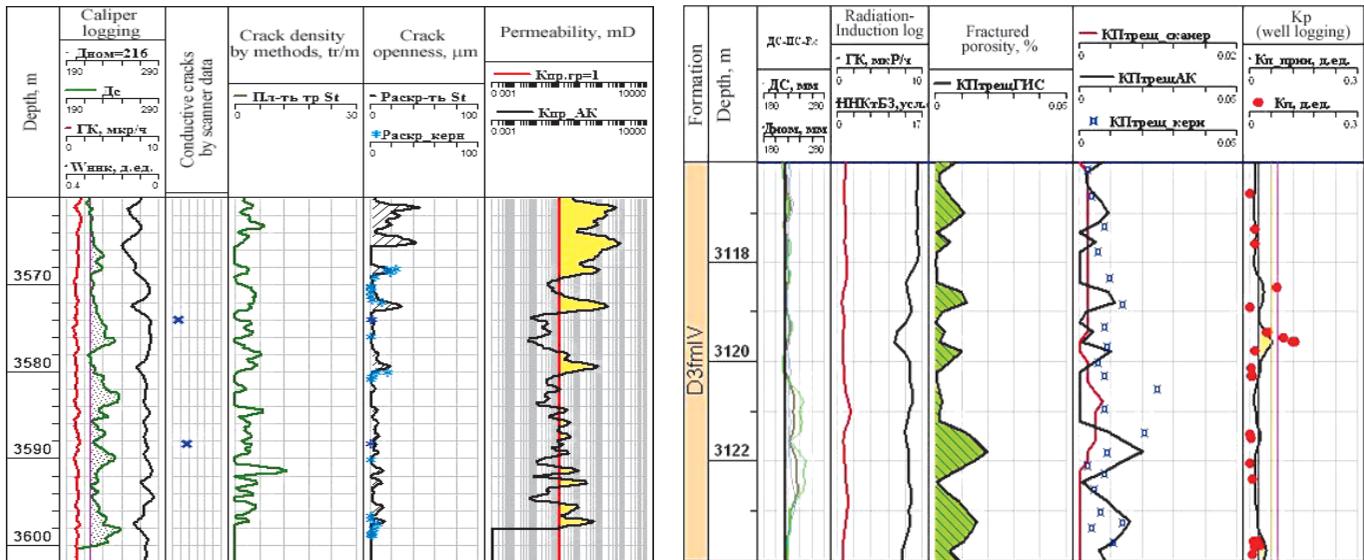


Fig. 12 Comparison of fracture opening and density, defined according to the sonic log data and on a core column

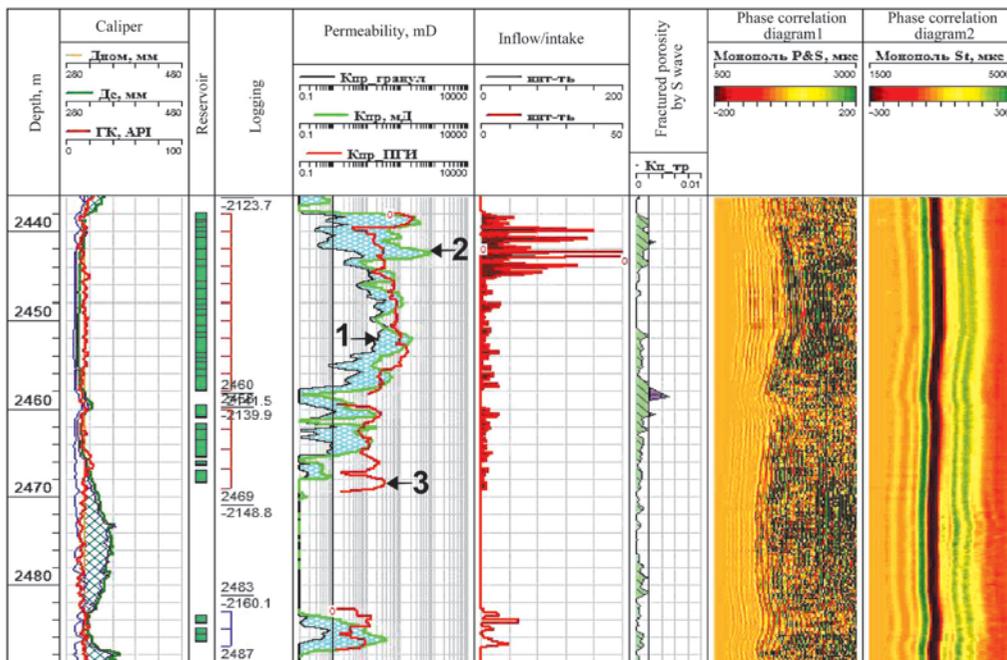


Fig. 13. Examples of determination of capacity and permeability associated with the fracture system, comparing different methods of porosity calculation

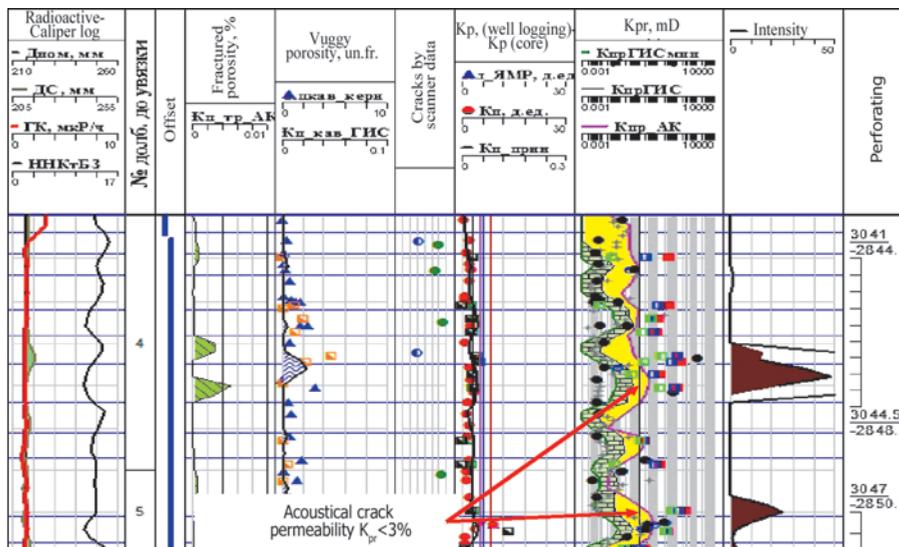


Fig. 14. Examples of determination of capacity and permeability associated with the vuggy-fractured system



## Conclusion

This article covers only a small range of possible studies. A cluster of studies, conducted during the formation drilling (geological and engineering surveys) hydrodynamic studies, tracing issues still have to be reviewed. Joint work with seismic specialists to study stress and shear zones can therefore constitute a major stage. And, in our considerations, we should be mindful of the proven methods of fracture zones allocation on such widespread complexes as radioactive logging, lateral log, and micro-laterolog.

There are many examples of rapid flooding, examples of financial losses due to lack of knowledge of the type of pore space. As a rule, the study of the impact of fractures at the field begins after receiving extremely negative consequences (Ostrich policy) and this is the main reason why the regulations controlling the amount of research are necessary.

There should be a report on research and findings, which is passed to the state structures controlling the subsoil study and, most importantly, which will be sent to a new subsoil user in case of a change. Perhaps it is necessary to create polygons, where methods of working

with such rocks will be practiced, including geophysical well survey techniques. At a minimum, it is useful to have three polygons with the presence of fractures, conditionally divided into types: 1 – low porosity; 2 – variable porosity; 3 – bitumenosity, organic.

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