

## Formation evaluation and well-test analysis for complex interpretation of reservoir permeability distribution

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**Abstract.** Data on heterogeneity of porous space and reservoir filtration properties determines the choice of most effective development strategy. The comparative analysis of well-logging and well-test results was carried out to determine the value of filtration heterogeneity. The similarity of the results obtained using different methods makes it possible to predict orientation of enhanced permeability.

The main aim of the maximizing oil production is to choose the most appropriate and efficient development strategy. This is not an easy task but a 3-D simulation model which shows the real hydrocarbon production rate can be applied to cope with the task. However, it is necessary to take into account that the simulation model is based on a geological model, within which reservoir properties are distributed in a particular way, with the most important property being permeability, especially, its distribution through the effective porous space.

There are two basic methods applied to determine the permeability anisotropy: a special core analysis and well-test analysis [1]. But these methods are time-consuming and expensive. Another method to obtain data is formation evaluation analysis. Well-logging data is recorded at every drilled well and it is possible to evaluate permeability values through the analysis of a cross-section. To predict the spatial anisotropy of reservoir heterogeneity it is essential to provide a special analysis of the well-logging data but with obligatory comparison with core and well-test data. The integration of various methods is aimed at reaching the maximum accuracy and efficient forecasting of permeability distribution.

This condition determines the specific requirements to the area of study. It should be a “standard deposit” which shows the explicit evidence of filtration heterogeneity confirmed by development operations, well-tests, well-logging and core analysis data. From this point of view XYZ deposits located in West Siberia meet the requirements to the full extent and have a sufficient set of logging and well-test data. Standard logging, gamma ray logging, self-potential, induction logging, neutron logging, lateral logging, core analysis and tracer investigations were conducted within the entire area of the field. Using this suite of methods it is possible to detect reservoirs, evaluate porosity, permeability, and prove shaliness model validity [2]. The log-inject-log tests which are aimed at determination of permeability value and tracing fluid volume during the flow from an injection to a production well are carried out as well.

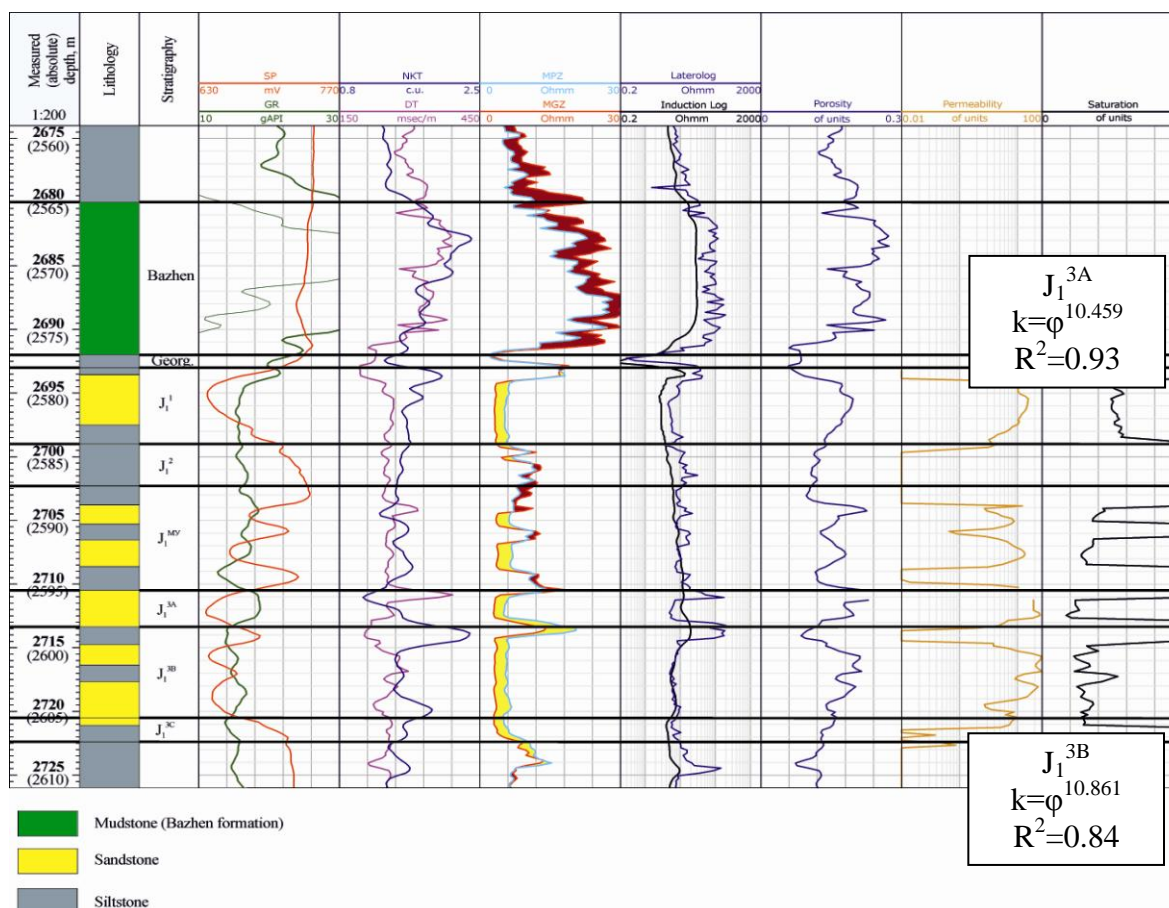
The geological structure of the field is characterized by siliciclastic formations with changing lithological composition of Mesozoic and Cenozoic platform mantle as well as pre-Jurassic basement. The total thickness of discordant deposits which occur on the basement comprises about 3 km. The north-eastern stretch of the geological bodies predetermines spatial anisotropy of reservoir properties.



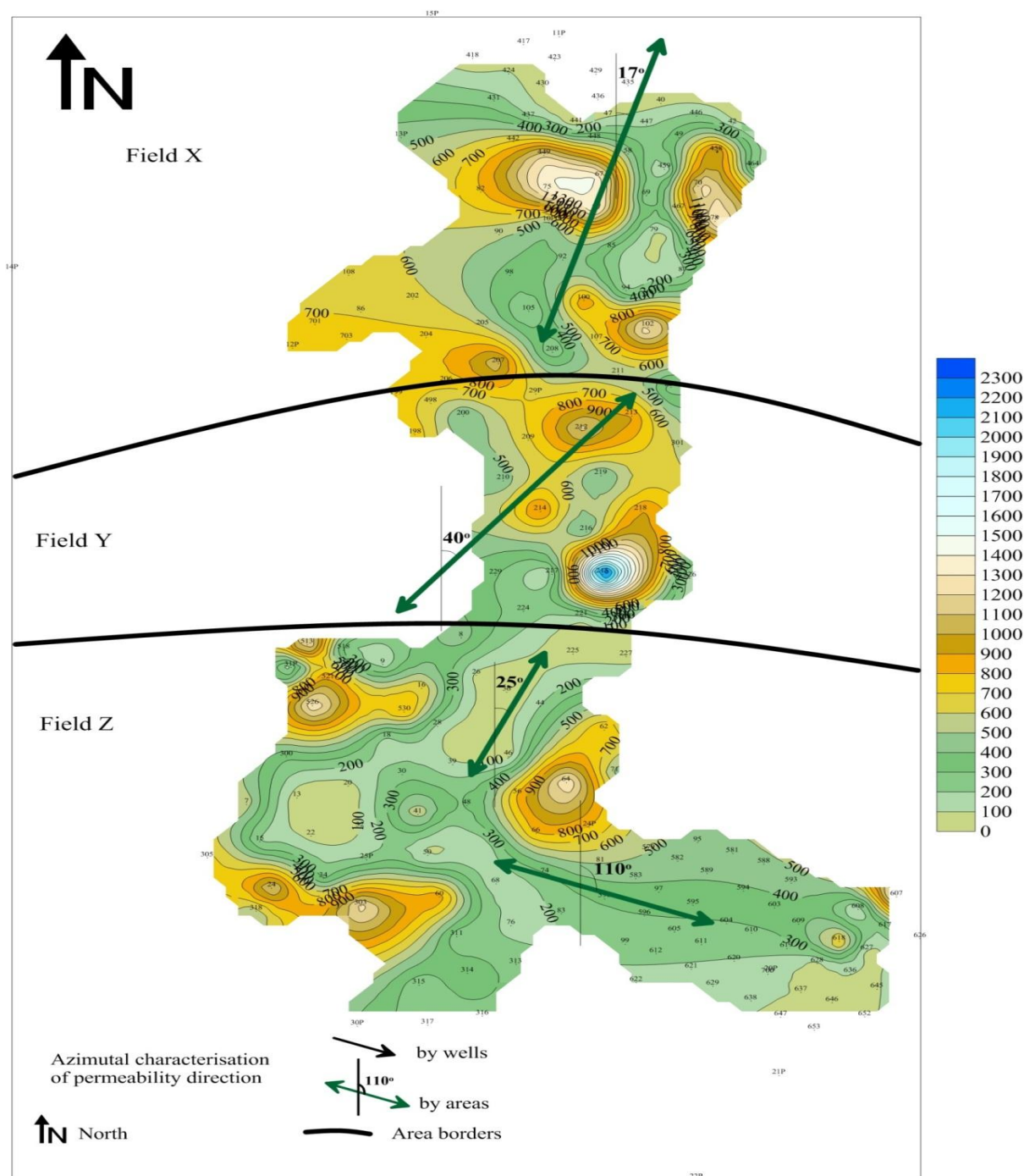
From the stratigraphic point of view the net-pay reservoir is composed of Upper Jurassic deposits and can be located through detection of reference horizon – the Bazhenov suite (which is characterized by the extremely high gamma-ray values). The reservoir is subdivided into four sublayers ( $J_1^1$ ,  $J_1^2$ ,  $J_1^{my}$ ,  $J_3$ ), which occurred under different sedimentation conditions (figure 1). The  $J_3$  horizon is also divided into three sub-horizons ( $J_1^{3A}$ ,  $J_1^{3B}$ ,  $J_1^{3C}$ ) which are characterized by deterioration of the reservoir properties from top to bottom.

In the period from 2003 to 2009, tracer fluid tests were conducted on the area of the field in order to detect the directions of fluid flow from injection wells to production wells. The main parameter acquired from these tests is time required for a tracer fluid volume to flow from an injection well to a production well. These data make it possible to calculate the phase permeability of the reservoir.

The integrated analysis revealed that  $J_1^3$  is the most producing formation. The formation subdivision corresponds to reservoir property changes observed through the vertical section of the reservoir. The shaliness model was chosen using the self-potential method and the least shaly layer was taken as reference one. The porosity was calculated using the neutron method [3, 4]. The next step of interpretation procedure is concerned with the choice of the equation that will help to predict the permeability variations within the well section.



**Figure 1.** Petrophysical interpretation of vertical section (well 29P).

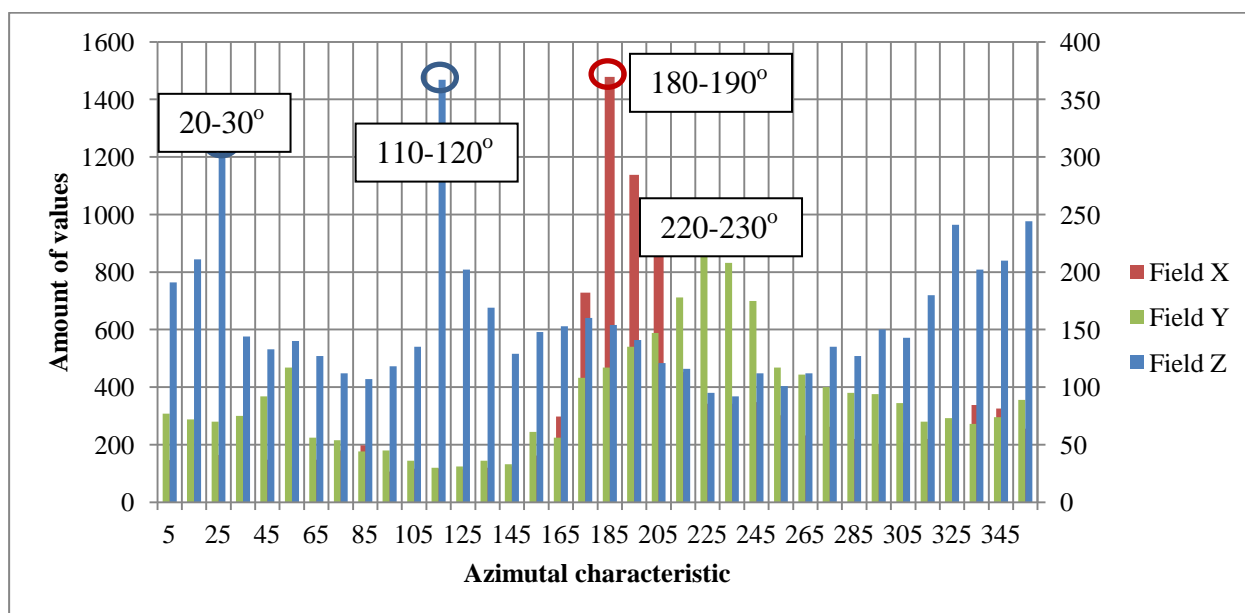


**Figure 2.**  $J_1^3$  permeability map and vector characteristics of isoline directions (permeability in mD).

To calculate permeability one must consider the correlation between permeability and porosity parameters obtained from the core analysis. Layers  $J_1^{3A}$  and  $J_1^{3B}$  show the high correlation which, in its turn, give an opportunity to apply the appropriate equations for permeability evaluation (figure 1). The correlation coefficient convergence suggests the identity in permeability distribution depending on porosity. Moreover, it is necessary to note that a closer connection between the parameters is observed for sub-layer  $J_1^{3A}$ . The obtained values characterize the section of the zone where well intersects the layer.

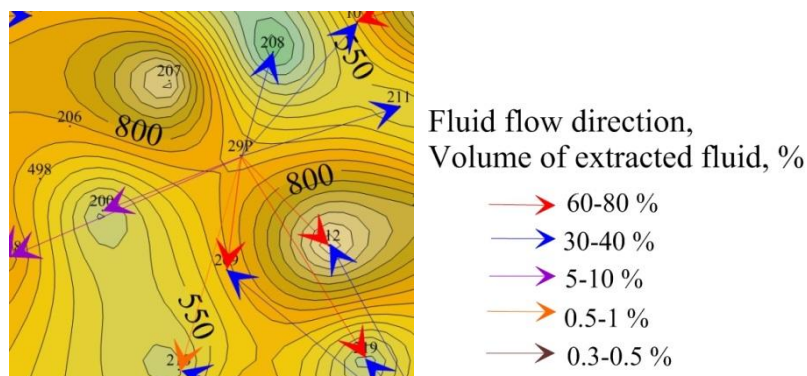
Production wells reflect the characteristic dependence between the volumes of extracted fluid and numerical data of permeability calculated with the help of petrophysical investigations. The map (figure 2) generated on the basis of data about the permeability distribution indicates spatial petrophysical heterogeneity of the layer (a special system of isolines). If the map is produced using the vector distribution of the azimuthal permeability orientations, the similar effect is observed as well.

It is possible to use vector analysis for permeability isoline orientation determination. The produced bar graph (figure 3) indicates not only heterogeneity but also allows calculation of orientation- angle characteristics of enhanced filtration [5, 6]. The segments with maximum values on the graph correspond to general directions detected by tracer tests. It is necessary to note that permeability heterogeneity is equally distributed in opposite directions [7, 8, 9].



**Figure 3.** Bar graph of horizontal permeability distribution based on well-logging data.

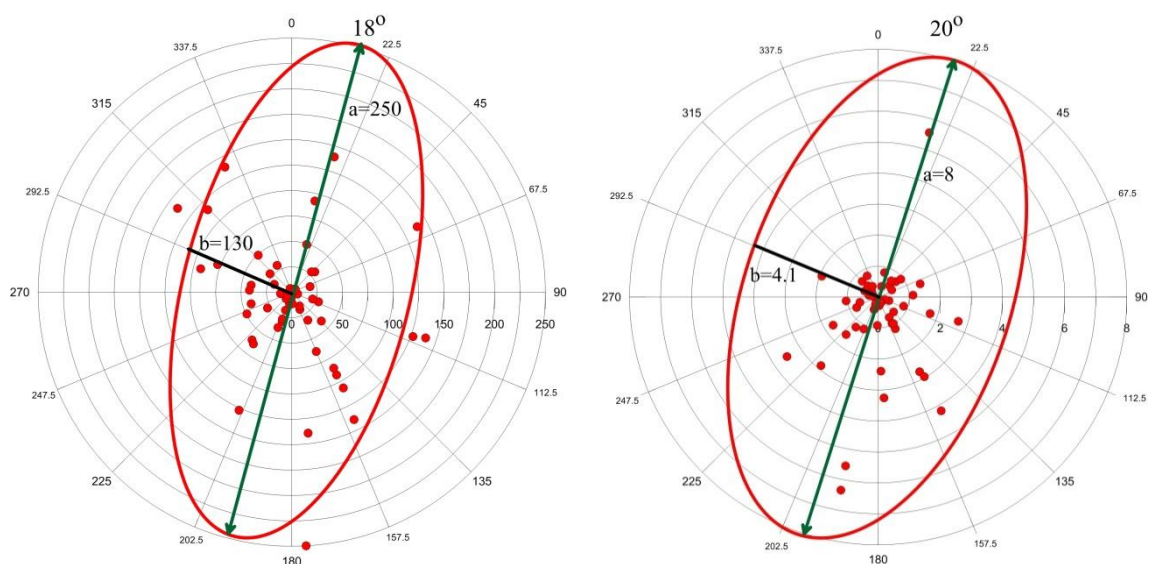
The distribution of permeability in layer  $J_1^3$  in proximity to the well 66 is presented in figure 4. Production wells are radially placed relative to the injection well. This type of displacement allows evaluation of the numerical characteristics of tracer research. Furthermore, the figure shows that the predominant direction of fluid extraction is north-eastern (south-western) one. The similar data are obtained as a result of phase permeability analysis.



**Figure 4.** Distribution of permeability (well 29P) according to well-test results (permeability in mD).

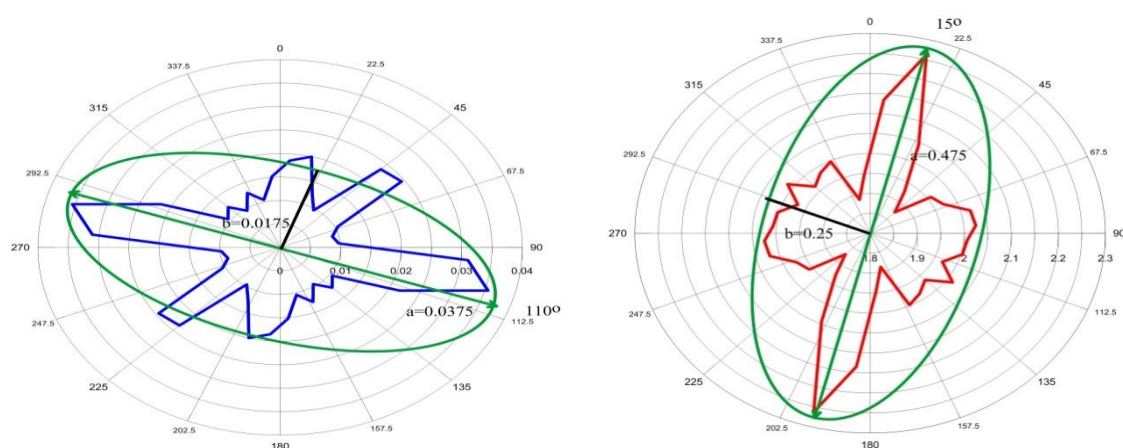


Elliptical approximation was applied to evaluate predominant filtration. As it is seen in figure 5, models produced with different methods correlate with each other by azimuthal characteristics. The absolute values of correlation sections (ratio of maximum to minimum ellipse axes) are nearly equal (1.92 according to formation evaluation data and 1.95 well-test data). The correlation section correspondence indicates that well-tests confirm formation evaluation data.



**Figure 5.** Elliptical approximation of permeability distribution obtained through well-logging (left) and well-test analysis (right).

The gradients of permeability distribution throughout the study area (figure 6) show the directions of approximating ellipses with respect to minimum and maximum values of gradients. Compression ratio in this case constitutes 2.14 and 1.9 and well-test data discrepancy makes 10% and 3%. Azimuthal location of the major ellipse axis (minimum gradients) corresponds to the distribution obtained in well-tests (figure 5).



**Figure 6.** Distribution of permeability gradients based on elliptical approximation results: minimal values (left), maximal values (right).

The comparison of data obtained through well-tests (log-injection-log) which are plotted on the regional map (figure 2) reveals coincidence in direction trends of high filtration. Moreover, reservoir flow characteristics studied through log-injection-log tests also confirm the results of vector analysis based on formation evaluation data.

Thus, formation evaluation data can be applied for interpretation and determination of potential azimuthal characteristics to detect zones of enhanced permeability. Additional vector analysis of permeability gradients and elliptical models give further confirmation to well-logging results. The forecast reliability is determined by the chosen technology of formation evaluation interpretation and accuracy of produced permeability maps.

## Conclusions

1. The results of well-tests are confirmed by areal permeability distribution obtained through petrophysical justification of formation evaluation data interpretation.
2. The initial conclusions about permeability heterogeneity on the area are advisable to make at the stage of well-logging data acquisition and processing. The necessary condition is capability to produce detailed maps of stratigraphic layers.
3. Vector analysis of permeability maps and gradient zones allows for reliable data on azimuthal and numeric characteristics of permeability heterogeneity for further geological and reservoir modeling.

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