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Recovery Improvement Using Geological, Technical and Operational Factors of Field Development That Influence the Character of Inflow Profiles in Horizontal Laterals

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Abstract

Currently, it is hard to imagine oil field development management without various surveys, involving resource optimisation for more economical reserves recovery. In this context, the application of new technologies aimed at diagnostics of the state of producing wells opens up multiple opportunities to identify the causes of premature water flooding and reduction in oil production, clarify the geology of the developed deposit, and obtain other useful information in a cost-efficient manner.

For several decades now, well logging has been the source of information for field operators on the producing reservoir performance and the composition of fluid flowing across the reservoir through target intervals. However, in the course of time, the industry tends to seek advanced technologies and alternative production logging techniques for well performance diagnostics. Marker-based production logging is just one of the techniques employed to obtain additional data that can be extremely important for prompt decision-making in case of any complicating factors. At the same time, such information requires proper processing and interpretation.

The information on how various factors impact the production profile helps develop a set of measures to adjust the oil flow into the well. In this regard, the task above offers a promising outlook for improving the development system efficiency using selective reservoir stimulation, as far as unconventional reservoirs and hard-to-recover reserves are concerned. Therefore, the upstream industry puts a strong focus on further research in this area today.

NEW APPROACH TO INCREASE THE EFFICIENCY OF HYDROCARBONS RECOVERY

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At the current stage, the purpose of the work was to evaluate the influence of various geological and engineering factors on the production profile of a horizontal well in order to develop a methodology for the advanced interpretation of marker-based production logging data.

Thus, the objectives of the research were as follows:

1. To identify the main patterns of the production profile behaviour depending on the geological and engineering factors.
2. To evaluate the possibility of obtaining a uniform flow profile in a horizontal well.
3. Obtain a series of data sets to test the CRM model.

TECHNOLOGY DESCRIPTION

Marker-based well logging technology

The new technology of production logging is based on the combination of marker-reporters made from quantum dots and a polymer shell. Quantum dots are nanocrystals that are 1-2 nanometers in size, obtained by colloidal synthesis and coated with a layer of adsorbed surface-active molecules. Quantum dots fluoresce in different areas of the electromagnetic spectrum, depending on their size. Markerreporters created from quantum dots have the unique ability to absorb energy in a wide range of the spectrum and emit a narrow spectrum of light waves, which can be recorded using cytofluorimeter.

The use of quantum dots in marker-based technology is due to the large number of possible combinations, called signatures, there are more than 60. Each stage or interval uses its own unique signature for each phase of fluid.

Different types and combinations of marker-reporters with a size of less than 1 micron are introduced into the polymer coating of the proppant for multi-stage hydraulic fracturing or composite polymer for downhole cassettes. The polymer coating is gradually used through contact with oil and water and markers containing quantum dot unique signatures are contollably released in the flow. The general scheme of workflow profile is presented in Figure 1.

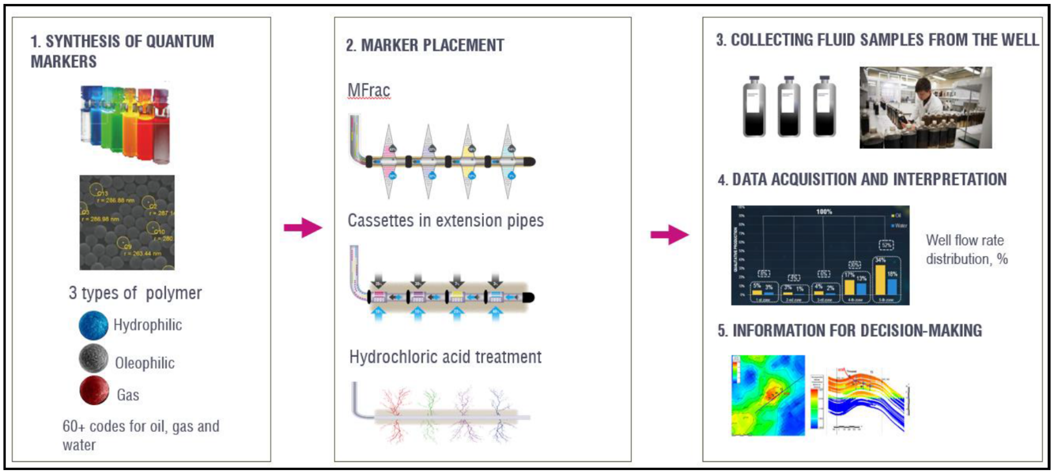

Figure 1—Scheme of workflow profile

When the well is put on production the marker-reporters are controllably washed out with the formation fluid over a long period of time. During sampling from the wellhead and subsequent laboratory analysis, the analytical system supported by machine learning software determines the quantity of markers corresponding to each code (Figure 2).

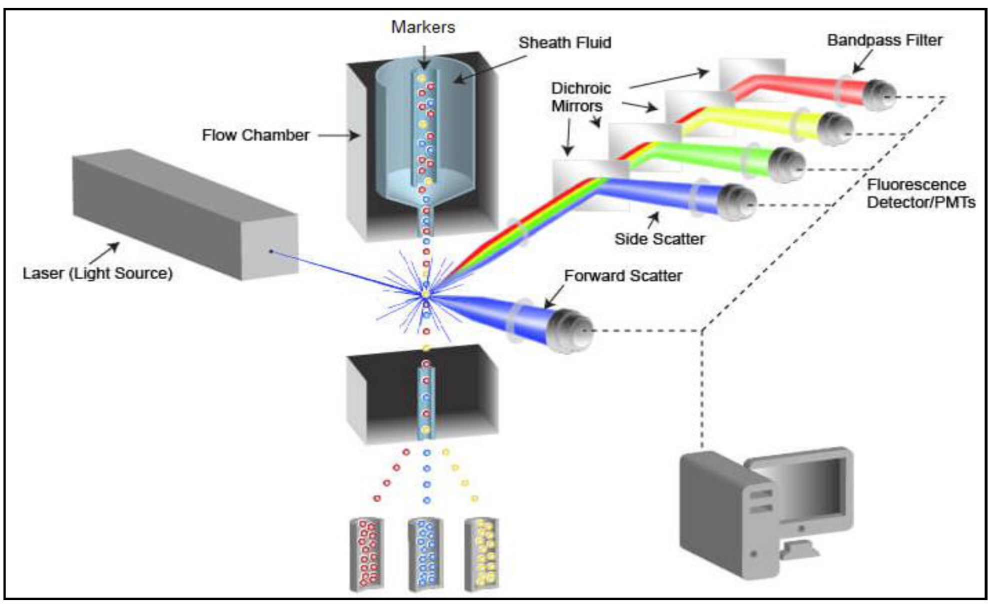

Figure 2—Scheme of the marker-reporters quantitative identification method with direct and side light scattering from a marker-reporter.

Each marker-reporter represents a point in the 15-dimensional space of coordinates, reacting to laser irradiation with manifestation in different wavelengths. Manually processing data on the quantitative determination of marker-reporters using only flow cytometry does not allow for an acceptable accuracy of determination. With a massive number of signals and a large number of signatures in the analyzed fluid sample, the task of quantifying and counting markers becomes difficult and time-consuming. In addition, it is nearly impossible to fully eliminate human errors.

The developers of the marker technology proposed an innovative data processing approach based on artificial intelligence. The program created by the developers of marker technology is based on machine learning using the "Random Forest" algorithm. Simply speaking, the principle of this operation can be described as follows: initially, the neural network is trained on "referee" samples of marker-reporters. From this, the so-called "decision tree" is built, where at each depth stage the parameters are sorted by a certain parameter such as whether a particle is excited in a certain range of the electromagnetic spectrum or not.

The depth of the "tree" may be different each time. The software creates an expansive variety of "trees" that all differ in structure. As a result, when passing through such a tree, the marker of the desired code falls into a strictly defined "basket". The trained algorithms understand which basket each particular marker code should fall into. Then a mixture of a large number of markers is examined on the created tree and sorted, i.e. the algorithm considers the number and type of markers in the mixture. Each tree makes its decision, or conditionally speaking, "votes" on the composition of the mixture. The use of formation fluid for training precisely from those proppants that were injected into the well allows a high accuracy to be achieved in data interpretation. In general, machine learning algorithms allow for processing a large array of data with a given accuracy in a short time frame and eliminate the "human factor".

The scheme of the "Random Forest" algorithm application and the schematic image of markerreporters' identification using this analytical system is presented in Figure 3.

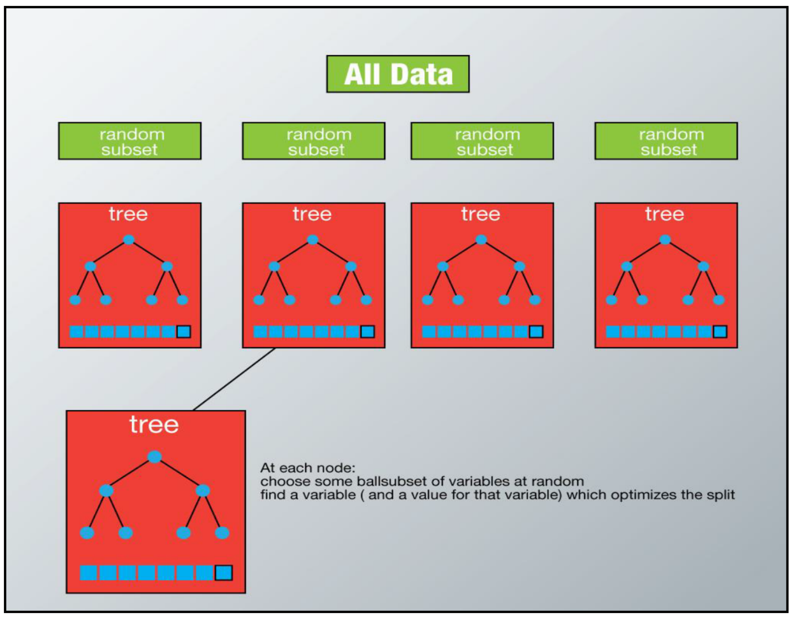

Figure 3—Scheme of the Random Forest Algorithm Application

There are several advantages to using quantum marker-reporters:

1. Monodispersity of markers in size. The lack of the tracers monodispersity causes significant errors that inhibit reliable quantitative analysis, as particles of different sizes have different sedimentation rates and, as a result, different relative flow rates in the well. Particles that are smaller in size will be carried away by the fluid flow faster than larger particles. In addition, particles of different sizes are distinguished by their ability to move with the formation fluid in the reservoir (Figure 4).
2. Automatic marker identification in formation fluid samples. The identification of markers is carried out using the automated analytical system in the mode of the item-by-item analysis without using microscopes. During the sample analysis, a strict number of marker-reporters are identified in each sample, thus ensuring accurate tests and eliminating errors associated with the human factor.
3. Uniform release of markers over an extended period of time. Marker-reporters injected into the proppant polymer matrix or granulated composite polymer for downhole cassettes ensure the stability of their release from the polymer coating.

4. Many marker signatures. Currently, there is the possibility of synthesizing more than 60 unique signatures of markers for hydrophilic and hydrophobic polymer coatings, which allows one-time diagnostics and monitoring of a significant number of horizontal well intervals or MultFrac stages.
5. No restrictions related to the application of markers in reservoir conditions. Markers show high physical and chemical stability, as well as resistance to aggressive environment and reservoir thermobaric conditions.

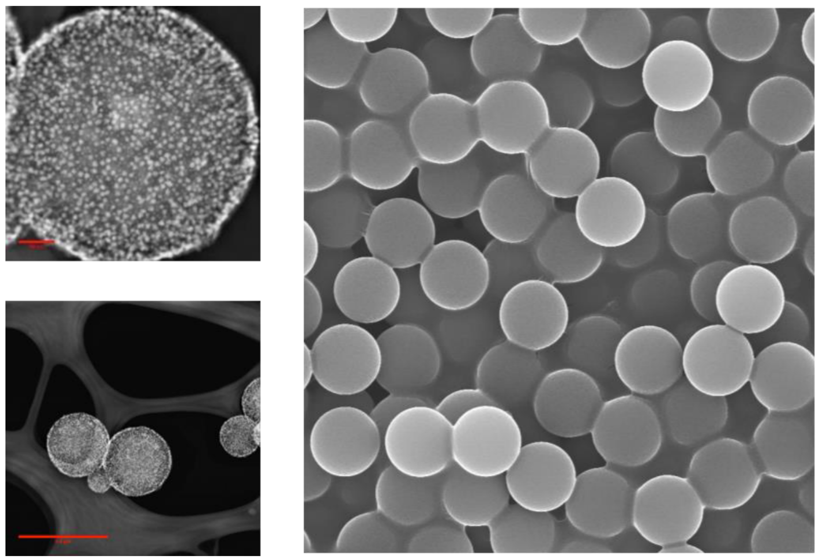

Figure 4—Photographs of marker-reporters with quantum dots made by scanning electronic microscope VEGA TESCAN.

Capacitance-resistance modeling (CRM)

Numerical reservoir simulation offers the best representation for reservoir fluid flow. However, uncertainty in assigning and distributing static parameters between wells adds a dimension of weakness to its implementation and cultivates modeling doubts. Capacitance-resistance modeling is one of the recent evolving technologies that provides opportunities to study fluid dynamic signatures that can help unveil uncertainties for some aspects of static reservoir parameters such as fractures and faults.

Capacitance resistance models (CRMs) comprise a family of material balance reservoir models that have been applied to primary, secondary and tertiary recovery processes. CRM uses production and injection rate data and bottomhole pressure, if available, to calibrate the model against a specific reservoir. Thereafter, the model is used for predictions.

We focused on three different control volumes for CRMs: the volume of the entire field, the drainage volume of each producer, and a drainage volume between each injector/producer pair. Unlike the numerical simulation approach, the CRMs use only production/injection data to predict performance, which provides simplicity and speed of calculation.

Once the CRM is calibrated with historical production/injection data, we use an optimisation technique to maximise the amount of oil produced by reallocating water injection rates. To verify CRM predictions, the models were tested against numerical flow-simulation results. Two case studies showed that the CRMs are able to successfully history match and maximise the amount of oil produced by just reallocating water injection.

In chemical engineering, the CRM is analogous to a single (or a series of) first-order tank storage model(s), where the flow rate into the tank is used to predict the level of the incompressible fluid inside and the outflow rate (Seborg et al., 2010). Fig. 1 shows a schematic of how the total production of slightly compressible fluids (oil and water) responds to a step-change made on an injection rate in the CRM. The shape of the output response caused by a stepchange in injection rate depends on the time lag and attenuation between a producer and an injector.

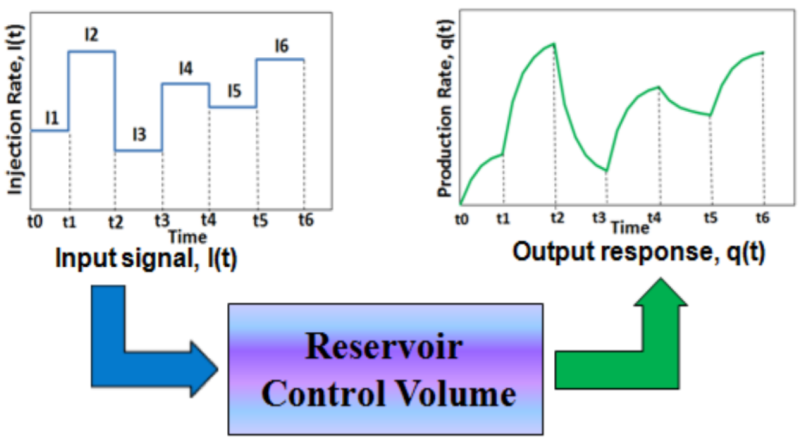

Figure 5—Schematic representation of the impact of an injection rate signal on total production response for an arbitrary reservoir control volume in the CRM (Sayarpour, 2008)

There are many documented limitations to this tool that reduce the model reliability or prevent it from attaining an acceptable match. Capacitance-resistance modeling limitations result from varying model parameters, or missing input data. Examples of these limitations include changes to the number of active producers, significant change in well productivity index (e.g. well workover), high variation of fluid compressibility, and presence of aquifer support. Most reservoirs will encounter many of these limitations which makes it important to find a rectifying solution.

Increase Complexity of Well Operation Monitoring Results and Stochastic Modeling

The resource recovery efficiency in horizontal wells treated with multi-stage hydraulic fracturing can be improved upon conducting a detailed study of the flow profile at frac ports, evolving in the course of well operation. Interpreting the obtained data appears to be quite challenging since there are many factors impacting the flow profile. Therefore, to make the production logging data analysis reliable, it is necessary to take into account the main effects responsible for the formation of a specific flow profile. For the purposes of this paper, it is proposed to use not just a basic reservoir flow model that reflects fluid production under ideal conditions set, but rather to apply stochastic modeling (CRM) involving only real historical operation data for all wells falling within the scope of the survey. This approach enables multiseries calculations of various patterns of the interference between nearby wells and obtaining typical flow profiles for each specific case. In other words, this helps estimate the contribution of each factor in the flow profile formation along the wellbore. The information obtained can then be used to interpret the results of field studies and to identify the factors affecting the degree of reserves depletion during the production process.

The main factors affecting the production profile and composition can be grouped into two main categories: geological and man-made factors. The geological factors include reservoir porosity and permeability, the presence of barriers (non-reservoir rocks), reservoir compartmentalisation, and the properties of reservoir fluids, such as pressure, volume, and temperature (PVT). Man-made factors include those arising in connection with a certain field development technique. These are the field development system as a whole, the presence of a reservoir pressure maintenance system, reservoir drive, well geometry, the agent injected, well operation methods, etc. A wide variety of diverse factors pre-determine a broad set of solutions. Further on, to keep things simple, we will discuss the impact of only certain parameters mentioned above on the horizontal well production profile and a hydrocarbon reserves production pattern.

Before the simulations, basic options were selected, assuming facies inhomogeneity of the reservoir and the hydraulic fracturing parameters. The options were selected based on the following assumptions:

- the need to take into account an inhomogeneous permeability profile of the reservoir zones;
- the need to compare horizontal wells with and without hydraulic fracturing in terms of production performance;
- the need to study how the hydraulic fracture propagation direction affects field development efficiency;
- the need to account for the impact of the reservoir pressure maintenance system on the productive interval performance;

Facies inhomogeneity in the formation geology was described as the permeability profile inhomogeneity. The channel-like inhomogeneity was considered, i.e., an extended reservoir zone with increased permeability relative to the main reservoir body (Figure 6). Two scenarios were considered with the "channel" located in the center (Figure 6, b) and at the edge of the formation (Figure 6, c). The scenario of a homogeneous reservoir with uniform permeability was also considered (Figure 6, a).

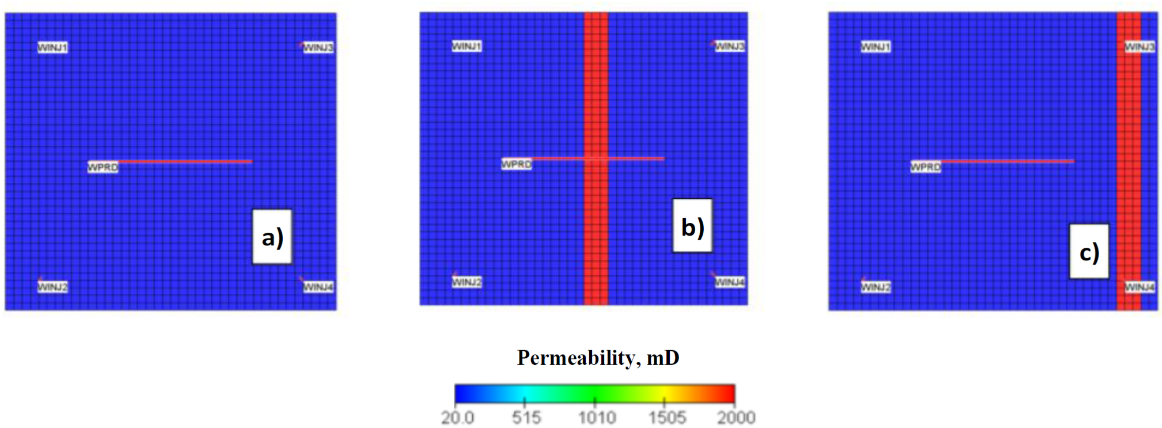

Figure 6—Absolute reservoir permeability for different geological conditions: a) homogeneous formation; b) channel-like facies inhomogeneity (in the center of the formation); c) channel-like facies inhomogeneity (at the edge of the formation)

In addition, some scenarios with the presence of non-reservoir zones in the formation are considered:

- Non-reservoir in the center of the formation; • Non-reservoir parallel to the horizontal well;
- Non-reservoir at a right angle.

This inhomogeneity was described as the lithology cube inhomogeneity.
Additionally, the general concept also included scenarios with different locations of hydraulic fractures. Table 1 describes the basic scenarios.

Table No.1—Reservoir models

Scenario no.	Geology	Type of deposit	Position of the horizontal well in the reservoir	Hydraulic fracturing
1	Homogeneous	purely oil zone	In the center of the formation	Without hydraulic fracturing
2	"Channel" in the center of the formation;	purely oil zone	In the center of the formation	Without hydraulic fracturing

Scenario no.	Geology	Type of deposit	Position of the horizontal well in the reservoir	Hydraulic fracturing
3	"Channel" at the edge of the formation;	purely oil zone	In the center of the formation	Without hydraulic fracturing
4	Non-reservoir in the center of the formation;	purely oil zone	In the center of the formation	Without hydraulic fracturing
5	Non-reservoir parallel to the horizontal well;	purely oil zone	In the center of the formation	Without hydraulic fracturing
6	Non-reservoir positioned anglewise	purely oil zone	In the center of the formation	Without hydraulic fracturing
7	Homogeneous	purely oil zone	In the center of the formation	Hydraulic fracturing 90°
8	"Channel" in the center of the formation;	purely oil zone	In the center of the formation	Hydraulic fracturing 90°
9	"Channel" at the edge of the formation;	purely oil zone	In the center of the formation	Hydraulic fracturing 90°
10	Non-reservoir in the center of the formation;	purely oil zone	In the center of the formation	Hydraulic fracturing 90°
11	Non-reservoir parallel to the horizontal well;	purely oil zone	In the center of the formation	Hydraulic fracturing 90°
12	Non-reservoir positioned anglewise	purely oil zone	In the center of the formation	Hydraulic fracturing 90°

On the basis of these scenarios, the influence of the absolute reservoir permeability on the profile of the fluid flow to the horizontal wellbore as well as on the overall reserves recovery across the deposit were evaluated. Reservoirs with 5 and 20 mD permeabilities were considered. Typical flow profiles with the specified flow parameters are shown in Figure 7.

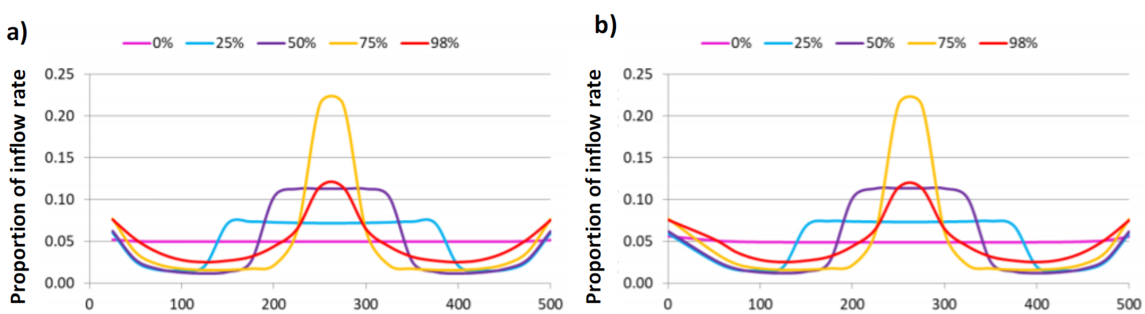

Figure 7.1—Inflow profile for 1-st model type a) 5 mD; b) 20 mD

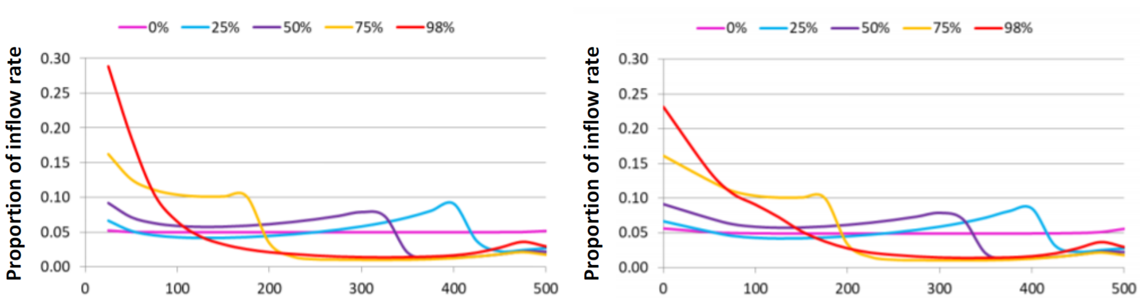

Figure 7.2—Inflow profile for 2-nd model type a) 5 mD; b) 20 mD

The analysis of the simulation results reveals that absolute reservoir permeability only slightly impacts the production profile and further reserves recovery. Thus, the decrease in the reservoir permeability did not lead to a considerable change in the distribution pattern of the fluid flow to the wellbore; only the timing changed.

The simulation of the selected basic scenarios revealed that the key factor affecting the non-uniform oil flow to the wellbore is the geological heterogeneity of the reservoir. A reservoir with uniform permeability shows minimal deviations among the production performance of different intervals. It is worth mentioning that this scenario is characterised by a slow increase in the fluid flow non-uniformity as the water cut grows. Simulations that include low permeability or zero permeability zones in the reservoir show a similar picture in terms of the non-uniform fluid flow to the wellbore, i.e. the distribution pattern reflected by the rate of curves is similar to that of the first case with a homogeneous reservoir, but the absolute values of the non-uniformity indicator are 2—2.5 times as large. In case of the scenario with a high permeability channel located at the edge of the formation, a higher indicator of the fluid flow nonuniformity is seen that grows rapidly over time along with an increase in the production fluid water cut. Depending on the non-reservoir zones positioning relative to the wellbore, the oil production profiles also diverge as the water cut in the extracted fluid increases. It is also noted that residual oil reserves are concentrated in the formation zones adjacent to the non-reservoir zones.

Subsequent simulation results with the involvement of hydraulic fractures display quite high rates of oil reserves recovery in the zone. If man-made fractures propagate through the reservoir zone with greater permeability, this scenario is characterised by a more intense per interval production with high production rates. It should be noted that high oil production rates can be maintained for a long time only in case of a uniform impact from injection wells. Otherwise, oil recovery rate decreases along with a sharp decrease in the duration of water-free production. However, the main factor affecting the fluid flow to the frac ports is also the geological structure of the reservoir.

No less interesting results were obtained from various adjustments of the injection process. Thus, for example, experiments with alternating water injection by start-stop cycle of well operation showed that if a horizontal well (both with or without simulated hydraulic fractures) is located in a reservoir zone with uniform permeability, a more uniform production profile is observed. At the same time, if some injection wells are located in a high permeability zone of the formation, stopping their operation from time to time helps reduce water cut and increase the oil recovery rate.

The experiments with the alternating operation of the injection wells have shown that this method offers significant potential in the development of reservoirs with porous inhomogeneous zones. If the injection wells are located in a high permeability reservoir zone, alternating their operation helps obtain a more uniform profile of both fluid and oil flowing to the horizontal wellbore along with:

- a longer water-free operation time;
- reduction in the reserves recovered at a high water cut in the production fluid,
- a higher ultimate oil recovery factor.

Results

The results obtained in the course of the research can be used to develop an algorithm for the marker-based logging data interpretation by selecting the simulated production profile patterns with the actual performance of the productive intervals obtained during field tests. The key idea is to address the principal objective, which implies obtaining typical well production profile patterns by simulating certain geological conditions and operation modes with the reservoir pressure maintenance system installed on the site. Thus, a set of such models along with extra a priori information on the development object (formation) may be used as the basis in order to quite reliably establish the factors responsible for the formation of a certain flow profile and identify the main flow processes occurring in the system under study.

Conclusions

Understanding of how various factors impact the formation of a horizontal well production profile can help develop various measures to control the oil flow into the well and select certain optimisation solutions that contribute both indirectly and directly to the increase in reserves recovery. In this regard, the objective mentioned looks promising as it can lead to improving the efficiency of the development systems using horizontal wells with multi-stage hydraulic fracturing. Therefore, further research in this field is of high relevance and significant practical value.

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