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Using Tracer-Based Technologies for Production Profiling in a Hydraulic Fracture to Optimise the Hydraulic Fracturing Design

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Abstract

The tracer-based surveillance technology can be used in hydraulic fractures to perform production profiling surveillance continuously for several years without the need for expensive and operationally risky interventions. The paper deals with the case of placing tracer coated marked proppant with different signatures in each hydraulic fracturing stage. In particular, it dwells on the experience of placing different signatures of tracer coated marked proppant within one port to evaluate the production dynamics of the far and near zones of a hydraulic fracture. The paper also offers methods for optimizing the hydraulic fracturing design to increase the hydraulic fracture production period and the cumulative production.

Introduction

Today the hydraulic fracturing technology is a well-tuned process both theoretically and engineering- wise. Over the 70-year history, this technology has undergone a dramatic transformation from single operations to massive application in production of hydrocarbons.

The main commonly known problem in reservoir fluid dynamics studies is the lack of methods that would enable direct observation or measurement of parameters determining particular reservoir flow phenomena or processes. Such studies include the problem of the hydraulic fracture propagation in deep oil- or gas-saturated low permeability formations. The hydrocarbon production rate after hydraulic fracturing depends on the permeable surface area and width of the fracture formed [1]. Thus, the main geometric parameters are the height, width and length of the fracture, which cannot be directly measured. In the case of hydraulic fracturing, the only measurable data are the surface wellhead pressure and the bottom-hole pressure. Moreover, the focus must be shifted from the actual pressure values to the effective pressure, i.e. the difference between the current pressure in the hydraulic fracture and the minimum in- situ stress.

The hydraulic fracturing technology carries large number of uncertainties:

- Geo-mechanical properties of the formation treated: Young's modulus and Poisson's ratio, which are of primary importance to model the development of a hydraulic fracture.

- Errors in the assessment of reservoir stresses, on the one hand, may result in restrictions to hydraulic fracturing due to the achievement of maximum wellhead treatment pressures, and on the other hand, massive proppant destruction in the fracture;
- Models used in the hydraulic fracturing simulators. Thus, [2] shows that mathematical models used in hydraulic fracturing simulators help predict different hydraulic fracture geometries.
- Evaluation of the fundamental hydraulic fracture parameters such as effective fluid pressure and performance, determined by fluid injection tests and numerous pressure matching methods, can yield different predictive fracture geometries;

Other complications (such as problems with the fracturing fluid, hydraulic fracturing fleet equipment, the human factor) can also result in significant errors in the hydraulic fracture geometry and, consequently, incorrect estimation of the flow rate after the hydraulic fracturing operation, Fig. 1. In addition, poor estimation of the fracture geometry during the development of the hydraulic fracturing design, on the one hand, may have financial implications (i.e. cost escalation), and on the other hand, bear the risk of a hydraulic fracture breakthrough into non-target zones, greater reservoir contamination by the fracturing chemicals, etc.

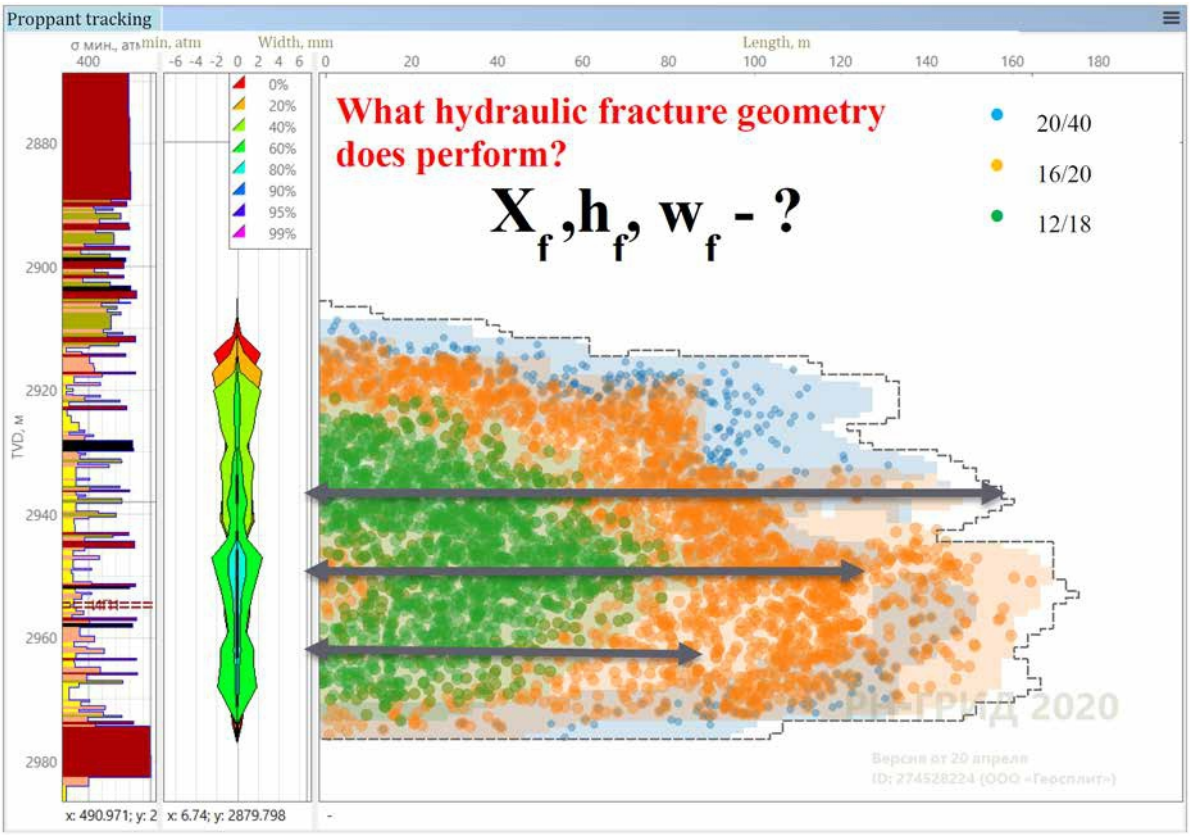

Figure. 1—Hydraulic fracture

Definitely, one of the main problems associated with hydraulic fracture performance is the change in the fracture geometry over time. It happens because the proppant is crushed under the action of compressive stresses and embedded into the walls of the hydraulic fracture. Another important circumstance is that the high Young's modulus of the rock, for example, in carbonate reservoirs can also facilitate proppant destruction. On the other hand, at low Young's modulus for poorly consolidated sandstones, proppant gets embedded into the fracture walls, thereby reducing the width of the fracture.

Proppant crushing and embedment tests in a hydraulic fracture (core analysis) are very specific and take a large amount of material and a long time, and therefore they are conducted quite rarely. Thus, the proppant behavior in the hydraulic fracture is pretty much understudied, meanwhile it strongly affects both the fracture geometry and the well flow rate. Fig. 2 shows the fracture degradation over time.

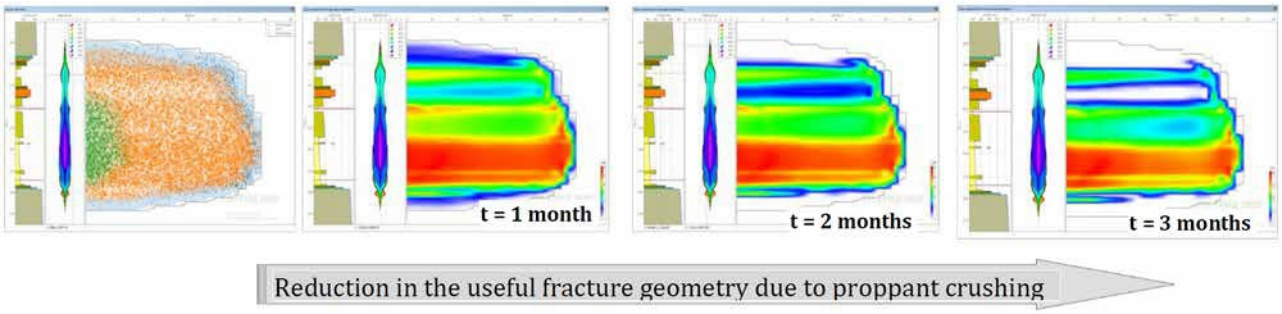

Figure. 2—Reduction in the useful fracture geometry due to proppant crushing and embedment

Existing methods for the hydraulic fracture geometry assessment.

Today the most commonly used methods for assessing the hydraulic fracture geometry are:

Micro-seismic monitoring (MSM)

Such information as the shape, dimensions, and direction of a hydraulic fracture propagation can help significantly optimize hydrocarbon production technologies. Currently, micro-seismic monitoring is conducted using both downhole and surface monitoring systems.

Fig. 3 shows how the stimulated volume is formed after multistage hydraulic fracturing in the Horn River basin [3]. *The micro-seismic analysis was conducted to identify the propagation of hydraulic fractures and evaluate the resulting asymmetry and azimuth of propagation.* Twenty-four-hour monitoring yielded a real-time picture of the fracture geometry and azimuth. These data can be used to elaborate the hydraulic fracturing model in order to optimize the next hydraulic fracturing stages at the site.

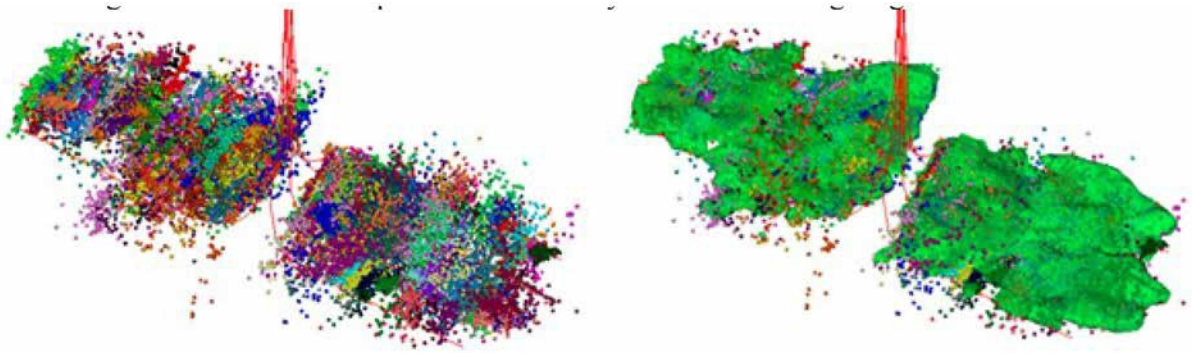

Figure. 3—Microseismic event scattering

Tests in hydraulically fractured wells.

The data of post-fracturing well tests are analyzed as follows:

- diagnostic logarithmic graphs are built to reveal the dependences of pressure and pressure derivative on time;
- flow patterns are identified on the basis of the derivative's diagnostic criteria and then time intervals are estimated;

The most commonly used method is Cinco-Ley type curve analysis for a finite conductivity fracture built on a logarithmic scale.

The Cinco-Ley type curve analysis of the well testing data helps identify the following:

- Permeability k;
- Fracture half-length;
- Dimensionless fracture conductivity FCD;

When designing tests for hydraulically fractured wells, it is very important to know the well test duration required in order to achieve a particular flow pattern. To evaluate the fracture parameters, a study must be conducted to record flow processes in distant zones with radial flow. To make the estimates accurate, the measurement time must be at least 10 times the measurement time taken for processes in the near and middle zones. All this requires extra materials and takes a longer time, which leads to financial losses.

Consolidation of the hydraulic fracturing data in the fracturing simulator

The simplest and most common method used for fracture geometry modelling and evaluation is the comparison of the data obtained with the model data in the fracture simulator.

The only parameters that are available to establish the current behavior of a hydraulic fracture, according to the Nolte-Smith technique [4], are the readings of the pressure gauge: a wellhead pressure gauge right during the fracturing operation, and a downhole one — after the operation is completed.

However, downhole gauges enabling real-time assessment of the hydraulic fracture performance are nevertheless rarely used since they are expensive. It is nearly impossible to estimate the hydraulic fracture geometry by the wellhead pressure dynamics, i.e. in real time, due to quite heavy friction pressure losses in the tubing.

Thus, the pressure data are consolidated after the fluid injection tests and recording of the pressure drop curve, Fig. 4. According to the result obtained, the model is adjusted for the actual data and the actual well flow rate, Fig. 5.

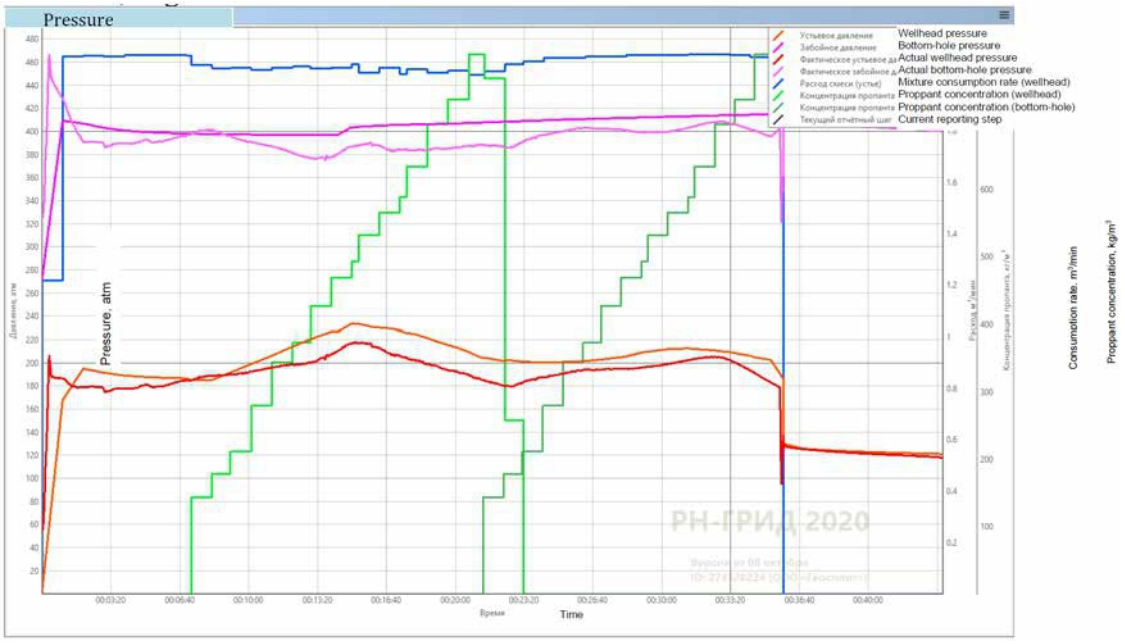

Figure. 4—Comparison of the hydraulic fracturing and model data in the simulator

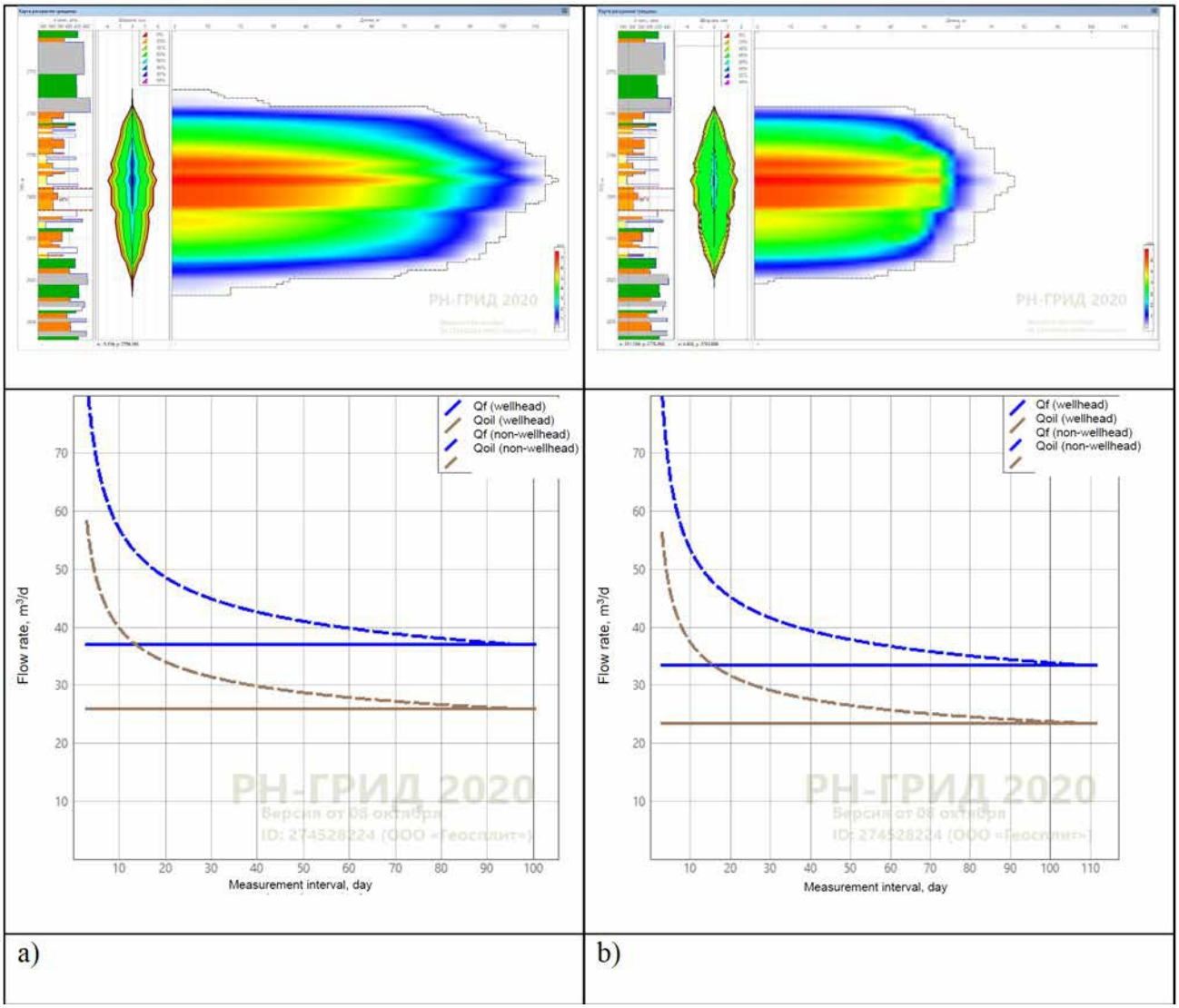

Figure. 5—Simulation results based on design a) and actual hydraulic fracturing operation b)

Use of neutron-absorbing proppant and logging techniques before and after hydraulic fracturing

Pulsed neutron logging (PNL) using a neutron-absorbing proppant, as well as acoustic or temperature logging, are designed for estimating only the height of the hydraulic fracture after its formation and characterized by a high error. The core idea is to perform logging operations before and after hydraulic fracturing with a subsequent assessment of the changes that occurred after the hydraulic fracture was formed.

Thus, the following summary can be made: the existing methods for estimating the hydraulic fracture geometry are either associated with a high degree of uncertainty or require massive amounts of correct input data to evaluate the resulting fracture geometry. Besides, there are no tools to evaluate the dynamics of the hydraulic fracture geometry over time.

The case of a 10-stage hydraulic fracturing operation presented below showcases a new method for assessing the hydraulic fracture geometry changes using the marked polymer-covered Geosplit proppant.

Evaluating the performance of different hydraulic fracture zones with the use of marked proppant.

Table 1 shows the geological and engineering data of well no. A of deposit B, pad C, formation D treated with a 10-stage hydraulic fracturing where marked proppant was injected.

Table 1—Geological and engineering characteristics

Item no.	Parameter	Value
General information		
1	Deposit	B
2	Well no.	A
3	Well pad no.	C
4	Type of well	Horizontal, production
5	Operation method	Artificial lift
Well data		
6	Number of production wells	1
7	Net pay, m	15.5
8	Average permeability, mD	0.4
9	Porosity, %	15.6
10	Reservoir pressure, atm	230
11	Reservoir temperature, °C	83
12	Number of hydraulic fracture zones, pcs	10

Hydraulic fracturing at the well no. A was performed in the period from 18 to 21 February 2020. Multi-stage hydraulic fracturing operations were performed using a cross-linked gel with fracturing fluid injected at the rate of 3.6 m^3/min, a proppant mass of 50 to 120 tons per hydraulic fracturing operation, and a 16/20 proppant fraction. The following amounts of GeoSplit marked proppant were used for each treatment stage: 15 tons for the final treatment stages and 15 tons for the first and the last operations with the supply of proppant at the first stages. It is noteworthy that the GeoSplit proppant injected during the first and last hydraulic fracturing operations was a 20/40 fraction when injected at the first stage.

The proppant was injected at the first and the last stages for the operations 1 and 10 to assess the contribution of the far zone of the hydraulic fracture and to answer the following questions: whether the hydraulic fracture has sufficient conductivity at low concentrations of the injected proppant and what the performance duration of the fracture far zone is.

The customer agreed to conduct a target multi-stage hydraulic fracturing operation, taking into account the geological characteristics summarized in Table 2. Fig. 6 shows the consumption rate, concentration, and injection of proppant.

Table 2—Information on hydraulic fracturing

Stages no.	Consumption rates, m3/min	V liquid, m3	Mprop, t	16/20	16/20 Geosplit	20/40 Geosplit	Geosplit proppant injection concentration kg/m3
1.10	3.4	320	100	70	15	15	100—600, 900
2.4—9	3.4	212	70	55	15	-	150—200
3	3.4	160	50	35	15	-	350—450

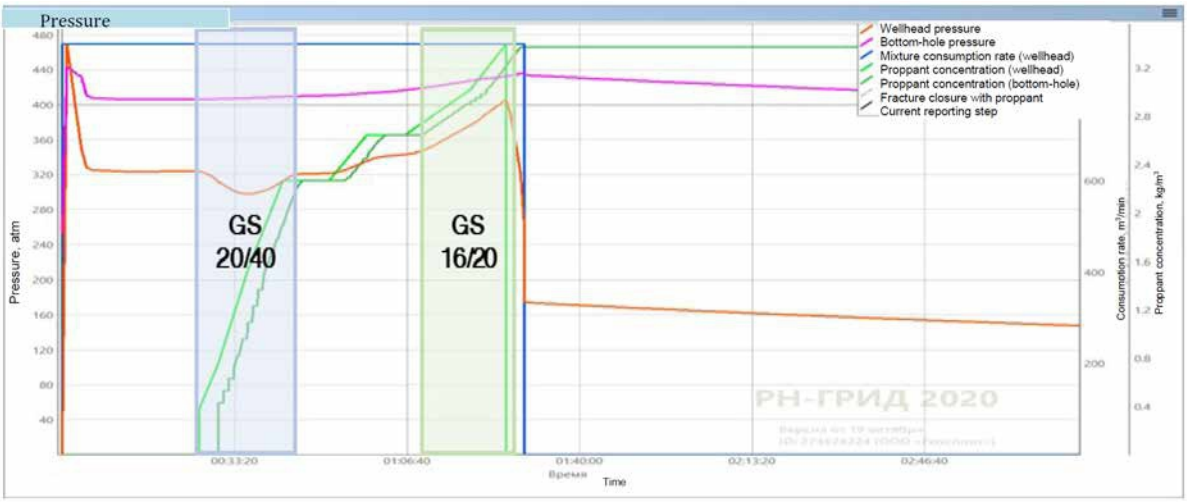

Figure. 6—Hydraulic fracturing treatment plan for stages 1 and 10

Fig. 7 shows the proppant distribution for the hydraulic fracturing stages 1 and 10. According to the simulation results, the 20/40 marked proppant fraction is observed at the periphery of the hydraulic fracture.

The marked proppant injected at the last stage is distributed across the entire bottom-hole zone, thereby ensuring the reliability of the recorded data provided by the marker-reporters that come from the entire hydraulic fracture interval together with the extracted fluid.

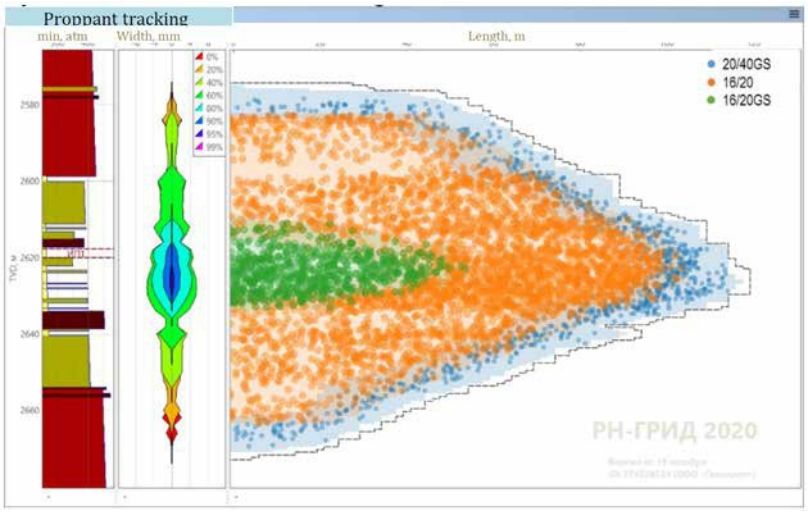

Figure. 7—Proppant distribution for the hydraulic fracturing stages 1 and 10.

Fig. 8 shows the proppant distribution (in total, 70 tons) for the remaining stages. Just like in stages 1 and 10, the proppant injected at the last stage spreads across the bottom-hole zone.

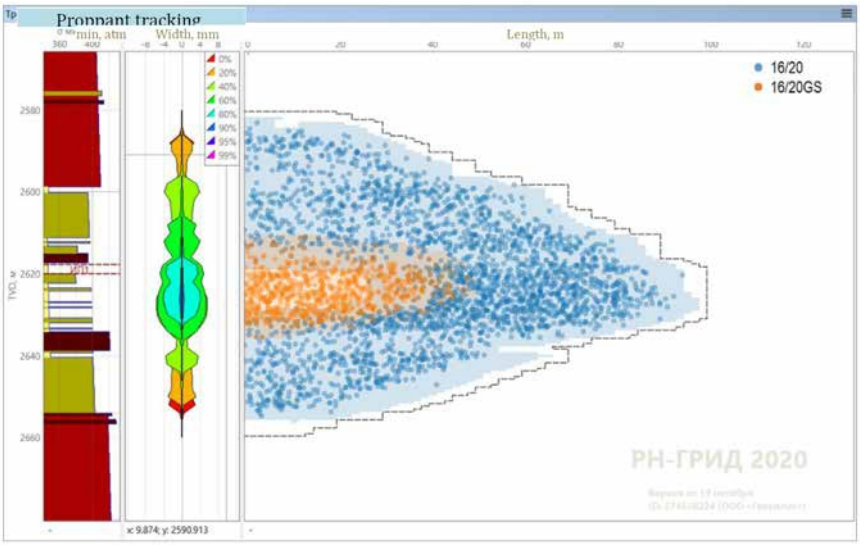

Figure. 8—Proppant distribution for the hydraulic fracturing stages 2 and 4—9

All hydraulic fracturing operations were performed normally, without any significant difficulties. The scheduled amount of proppant was injected into the frac stages. No breakthrough into the upper and underlying layers occurred.

Description of the marker-based production surveillance technology used in wells with long horizontal laterals penetrating formations with hard-to-recover reserves.

The marker-based production surveillance technology used in horizontal wells involves the use of quantum marker-reporters that are high-precision indicators of the reservoir fluid flow [5]. This method involves placing high-precision reservoir fluid tracers into conductive hydraulic fractures (with a fracture half-length up to 600 m). Once the multi-stage fracturing is completed and the well is brought into production, reservoir fluid samples are taken at the wellhead and analyzed for the quantitative distribution of each marker signature to reflect how the oil and water flow rates are distributed across the intervals.

Marker-reporters are polymer microspheres made of quantum dots, Fig. 9. Various quantum dot combinations form a marker code (signature).

In marker-based production profile surveillance, markers are embedded into the tracer coating of the proppant that is injected into the reservoir during multi-stage hydraulic fracturing [6]. Fig. 10 shows a marked proppant grain that contains markers in its polymer cover.

Proppant marked with a certain code is pumped down into each stage during multi-stage hydraulic fracturing as the last proppant pack to ensure maximum contact when washed by the reservoir fluid coming from the reservoir into the well Fig. 11.

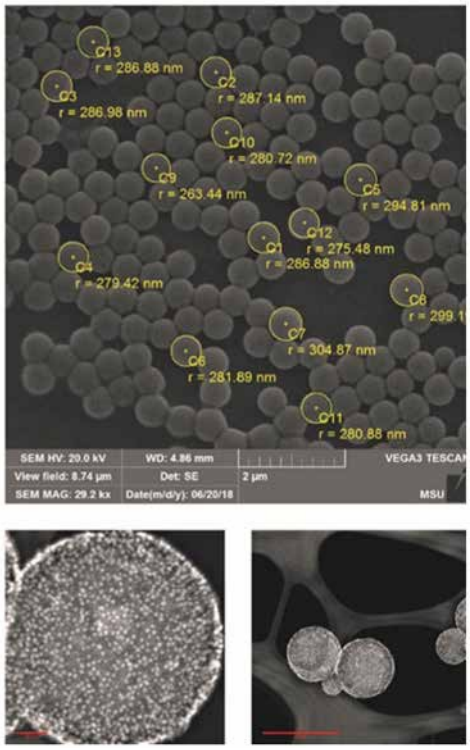

Figure. 9—A photo of marker-reporters in the scanning electron microscope

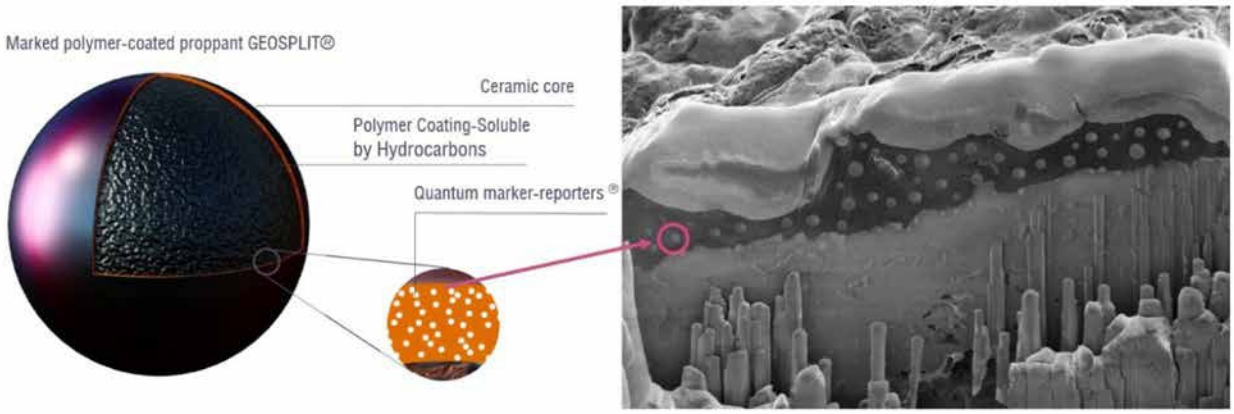

Figure. 10—A grain of the marked tracer-coated proppant with quantum dot marker-reporters

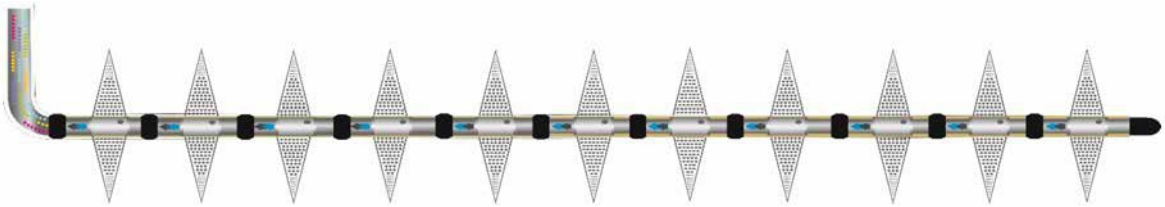

Figure. 11—Multi-stage hydraulic fracturing design with injection of marked proppant as the last proppant pack

Marked proppant may have three types of polymer coating: oleophilic, i.e. absorbing oil, hydrophilic, i.e. absorbing water, and a gas one.

As per the schedule, 15 tons of marked proppant are injected into each frac stage, which is a uniform 50:50 mixture of hydrophilic (targeting the water phase) and oleophilic (targeting the oil phase) proppant. Subsequently, the marker-reporters are gradually washed out by water or oil and are carried by the reservoir

fluid to the wellhead over the long period of the well's operation. Marker-reporters are released into both the HC and water phases of the reservoir fluid.

After the multi-stage hydraulic fracturing operations are completed and the well is brought into production, fluid samples are taken from the wellhead on a regular basis and further sent to the laboratory for analysis. Water and hydrocarbon phases are separated in the lab during the first stage, i.e. sample preparation, and then each phase is analyzed separately using analytical equipment and software. During the analysis, a small diameter fluid flow is formed.

(Fig. 12). The markers are lined up in a row and irradiated with a laser as they flow, which helps identify every single marker of each code based on the scattered light signal, direct and lateral. Thus, by analyzing the total quantity of the samples delivered, the contribution of each port in the total flow rate can be identified phase-wise (water and oil).

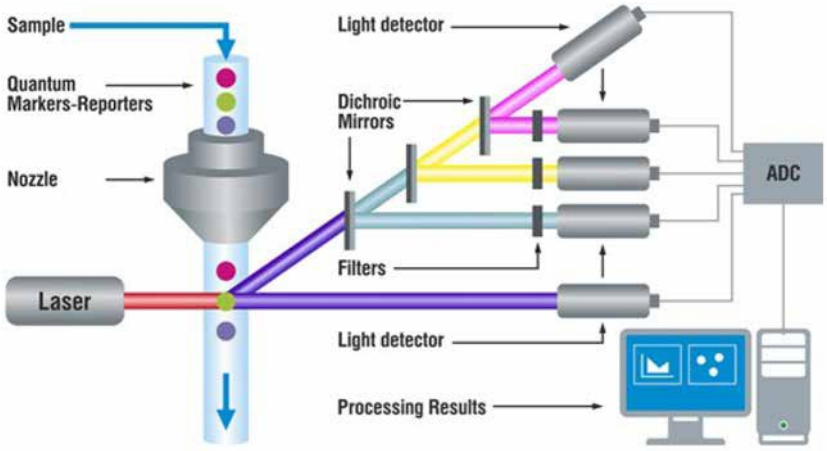

Figure. 12—Analytical equipment and software for flow cytometry

Machine learning methods, in which learning occurs as a result of analyzing solutions for many similar problems, are among the key elements of the technology. Production logging in horizontal wells is associated with processing of large amounts of data. For example, the data on the identification of each marker-reporter is a 15-dimensional point cloud, so manual calculations would require a lot of man-hours. For this reason, tracer-based production profiling surveillance method is supported by custom-tailored machine learning-based intelligent software using the Random Forest algorithm.

The basic underlying principle can be described as follows: initially, the neural network is trained using reference samples of marker-reporters to build a "decision-making tree", wherein parameters are sorted at each level (for example, whether the particle emits green light). A huge number of such trees with various structures is created. As a result, a marker with a specific code passes through this tree and gets into a strictly predetermined "basket". Trained algorithms "know" which "basket" each specific code should get into. Then a mixture of many markers passes through the entire tree and is sorted, i.e. the algorithm counts the exact number of each marker code in the mixture, Fig. 13.

In general, machine learning algorithms enable processing large data arrays with a given accuracy within a short time-frame, while avoiding human errors. Thus, this algorithm is a highly accurate and fast tool for analyzing incoming samples.

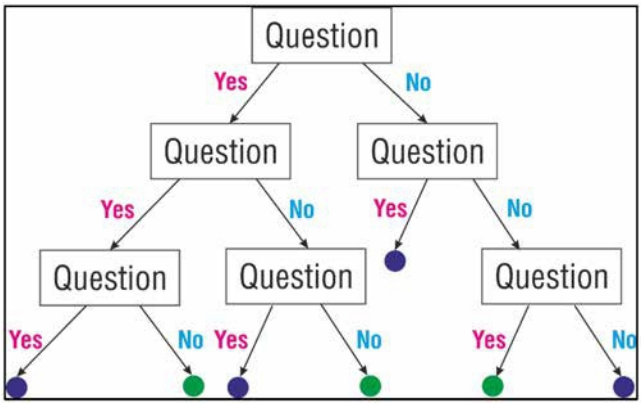

Figure. 13—Machine learning and decision tree building algorithm

Information about the tracer-based studies based on the result of the multi-stage hydraulic fracturing

Upon conducting the hydraulic fracturing operation, five samples were taken in the period from March to July 2020.

Fig. 14 shows the periods of reservoir fluid sampling for analysis in the laboratory of Geosplit.

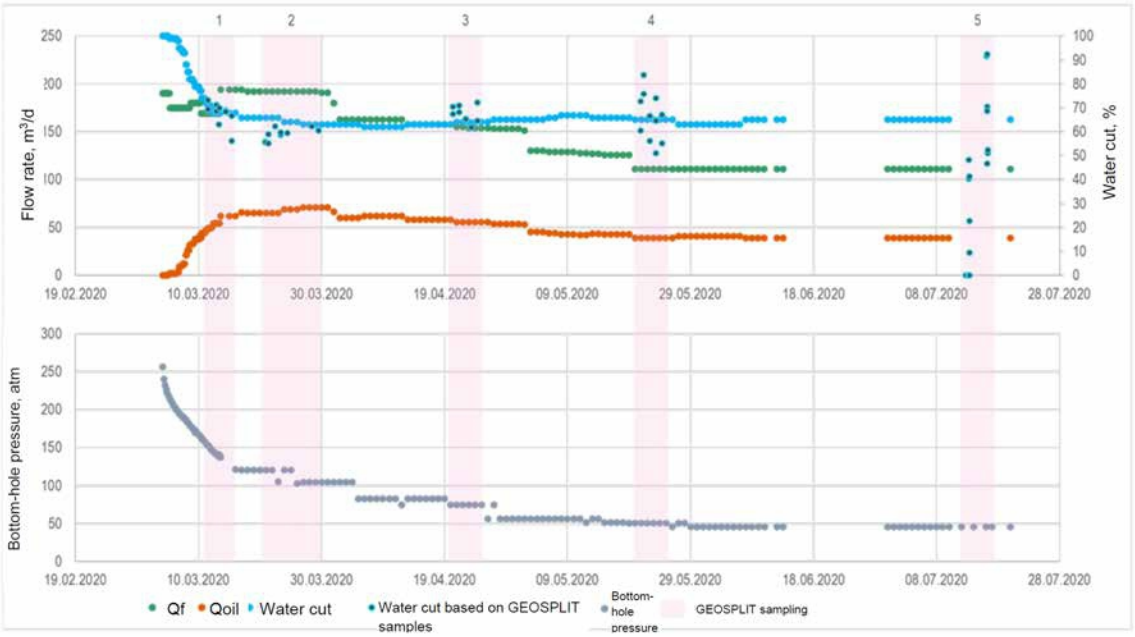

Figure. 14—Well A production record for the period from March to July 2020

The analysis of the production data on Well A revealed the following:

1. Bottom-hole pressure decreased by 205.4 atm during the five months of the study;
2. The water cut of the reservoir fluid decreased from 100% to 63% during the first month as a result of fracturing fluid flowback, and then stabilized at 65%;
3. The fluid flow rate for the first month increased from 169 to 192 m3/day and then decreased to 111 m3/day by the time of the fourth sampling period.

Fig. 15 below shows the dynamics of the well's producing intervals performance for the entire study period

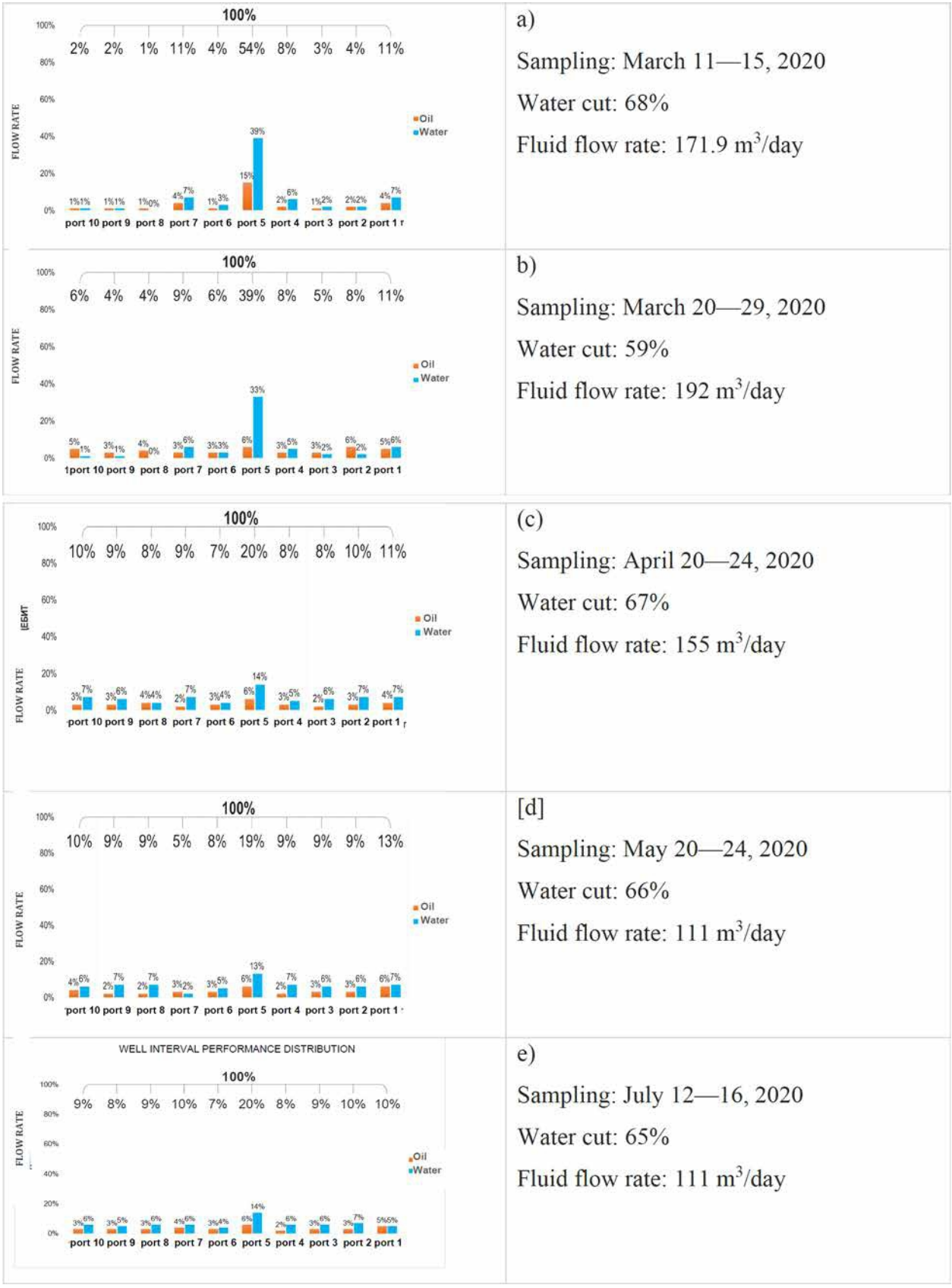

Figure. 15—Dynamics of frac ports' performance from March 11 to July 16, 2020

The study has revealed that production in port 5 significantly prevailed in comparison with other ports. The hydraulic fracturing operation at port 5 did not have any considerable specifics. According to additional information requested from the customer, the proppant spill in the port 5 interval was detected during the RIH/POOH operations, which led to a massive release of marker-reporters due to the flows from the ports 1—4 and the markers coming from port 5. During the subsequent cleaning of the bottom- hole, the contribution of port 5 decreased by 34% and, as a result, the production profile smoothed. The well under study had a non-uniform production profile during the first sampling period because the well was in transition to steady-state operation, and starting from the second sampling period, uniform and constant production has been observed in each multi-stage frac interval.

Water content in the reservoir fluid remained stable during the entire study period, ranging from 62 to 66% after the well's transition to steady-state operation.

Fig. 16 and Fig. 17 show the comparative dynamics of the contributions of near and far zones for frac ports 1 and 10, respectively. See Fig. 18 for the boundaries of the proppant distribution areas in the hydraulic fracture.

As seen in Fig. 16, the contribution of the near zone of port 1 to the entire well production increased by 20% during the study period. In addition, Fig. 17 shows that the performance of the near zone of port 10 improved a lot (the contribution increased by 46 %).

The studies in the near and far zones in ports 1 and 10 reveal that the contribution of the near zones is growing over time compared to the far zones. The production in the far zone prevailed in the first period of sampling, which perhaps may be attributed to the mechanical destruction of some proppant during hydraulic fracturing. However, during the second sampling period, the production profile underwent some transformation with the near zones becoming the major contributors in both port 1 and port 10, which is evidenced by the analyses of the subsequent reservoir fluid samples.

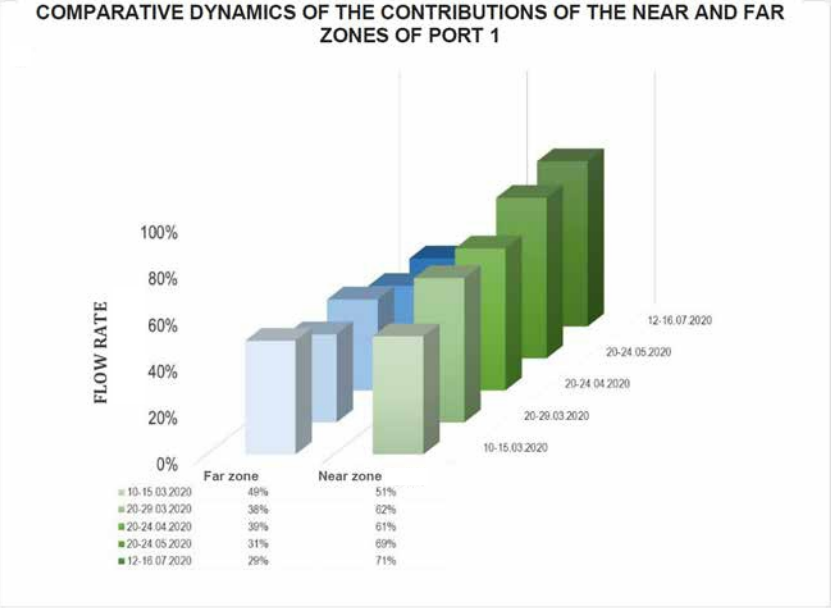

Figure. 16—Comparative dynamics of the contributions of the near and far zones for port 1 from March 11 to July 17, 2020

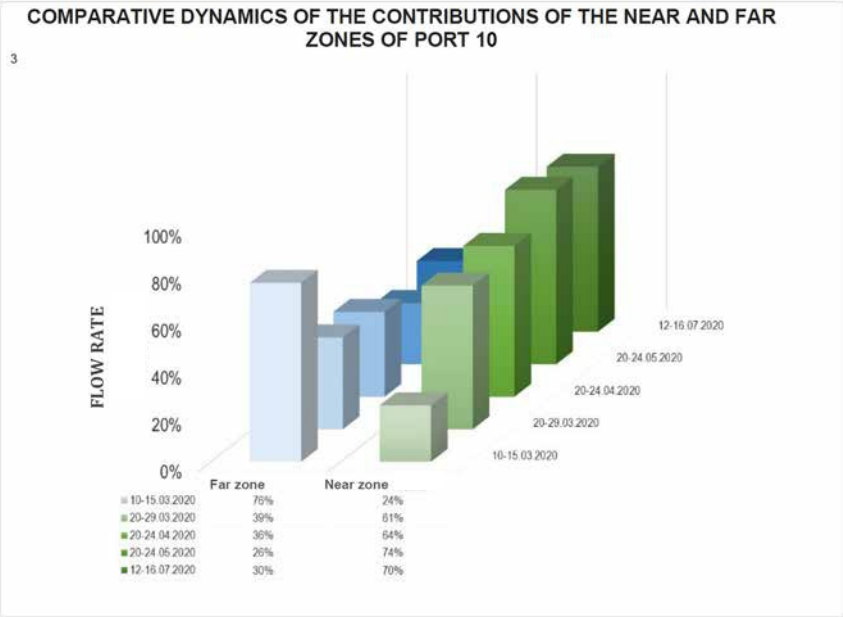

Figure. 17—Comparative dynamics of the contributions of the near and far zones for port 10 from March 11 to July 17, 2020

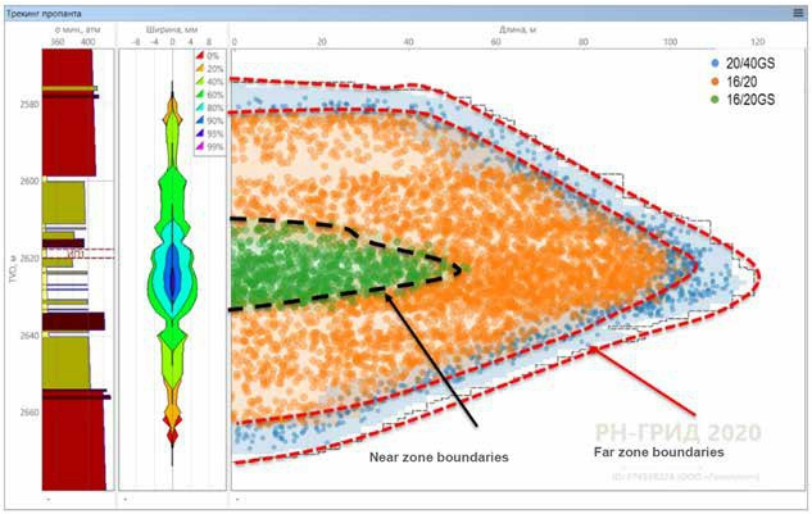

Figure. 18—The boundaries of the proppant distribution areas in the hydraulic fracture

Thus, it is safe to say that the proppant in the far zone covers most of the treated formation and contributes to the production of the hydraulic fracture.

Having the data on the decreasing performance of the far fracture zone, a simulation was performed with a decrease in the hydraulic fracture width by half for port 1 and by 2.5 times for port 10.

The destruction of the proppant cannot be directly modelled in the simulator. Since the fracture conductivity (the product of the proppant pack permeability and the consolidated width) are the key factors determining the performance of the hydraulic fracture intervals, the change in the fracture width over time was estimated neglecting the dynamics of the hydraulic fracture contamination by solids.

Fig.19 shows the consolidated hydraulic fracture width after the hydraulic fracturing operation and the flow rate. Notably, according to the first sampling (Fig.19 a) the flow rate of port 1 made up 10% of the total flow rate of ~ 17 m^3/day and 5.5 tons of oil.

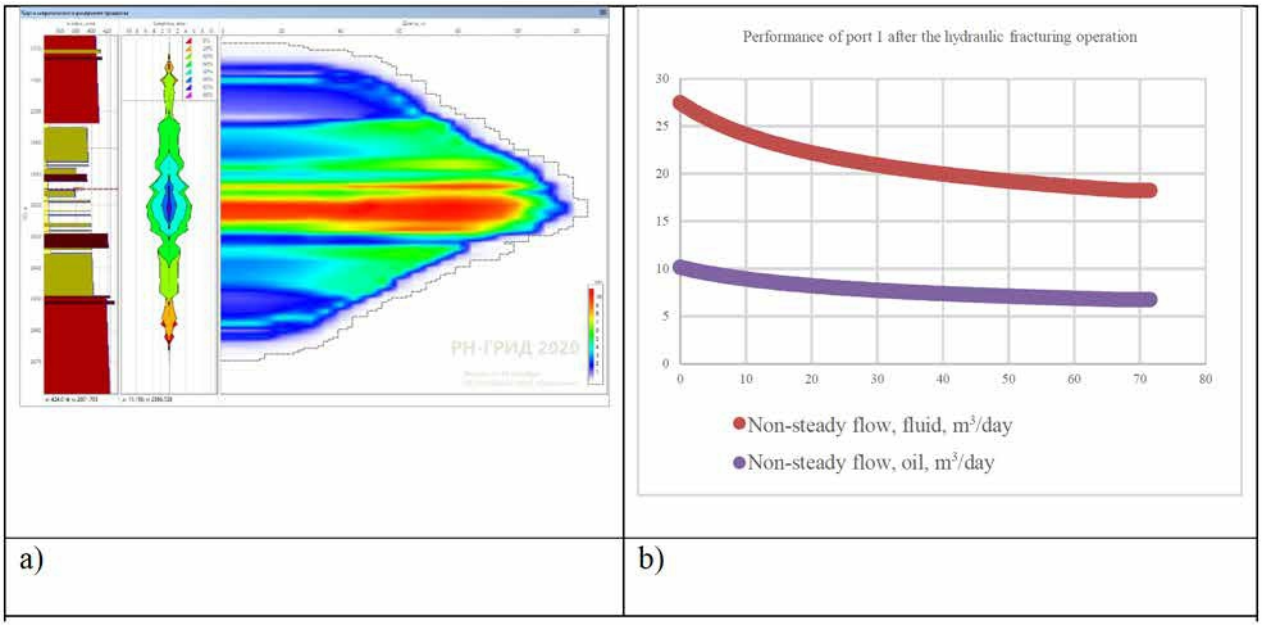

Figure.19—a) The geometry of a port 1 hydraulic fracture after the hydraulic fracturing operation b) Flow rate of port 1 hydraulic fracture

To fine-tune the model of the well production decrease during the sampling period, the function of reducing the consolidated fracture width by pressing the proppant into the hydraulic fracture walls was used. So, as seen in Fig. 20 d the well flow rate dropped to 111 m³/day and the flow rate of port 1 was 10%, thus port 1 contributed 11 m³/day, including 3.9 tons of oil. Fig. 20 shows the results of comparing the flow rate with the hydraulic fracture geometry, considering the proppant embedment.

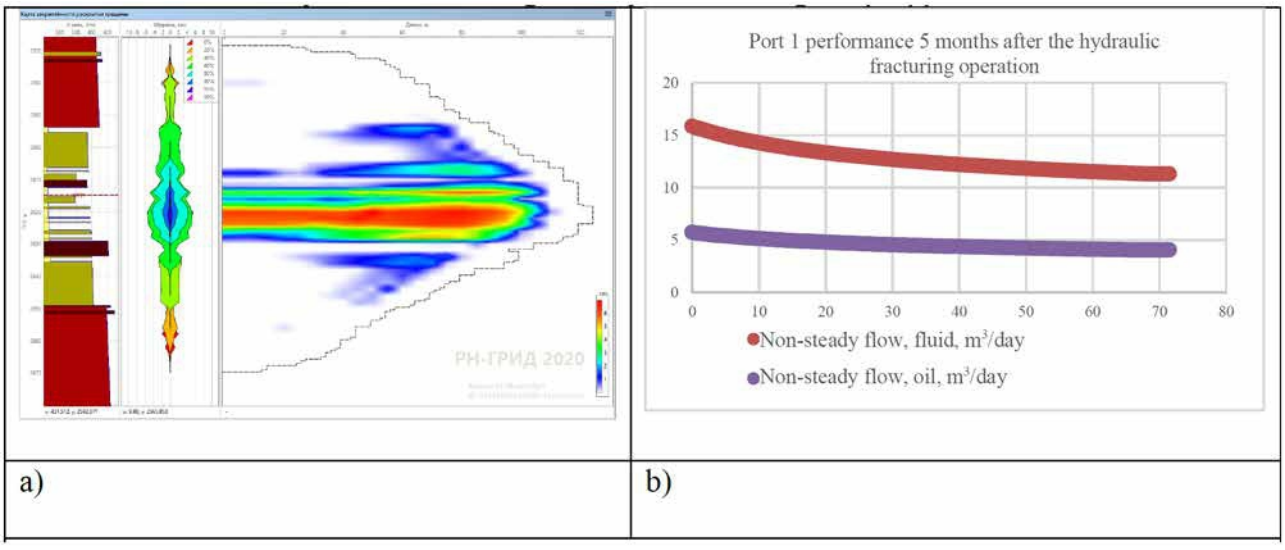

Figure. 20—a) Geometry of port 1 hydraulic fracture according to the result of the hydraulic fracturing operation b) Flow rate of port 1 hydraulic fracture

As can be seen from Fig. 20a, most of the hydraulic fracture a) is exposed to proppant crushing and embedment, which affects the fracture flow rate.

Taking into account a calibrated model showing the crushing and embedment of the proppant, the hydraulic fracturing design was optimized, i.e. the quantity of the injected proppant was increased to 130 tons, as well as the buffer stage quantity — to 100 m³, Fig. 21. a). Optimization of the hydraulic fracturing

design had a positive effect on the fracture flow rate at the initial stage, Fig. 21. b) and by the result of the well operation, which is confirmed by the consolidated hydraulic fracture geometry and the flow rate Fig. 22.

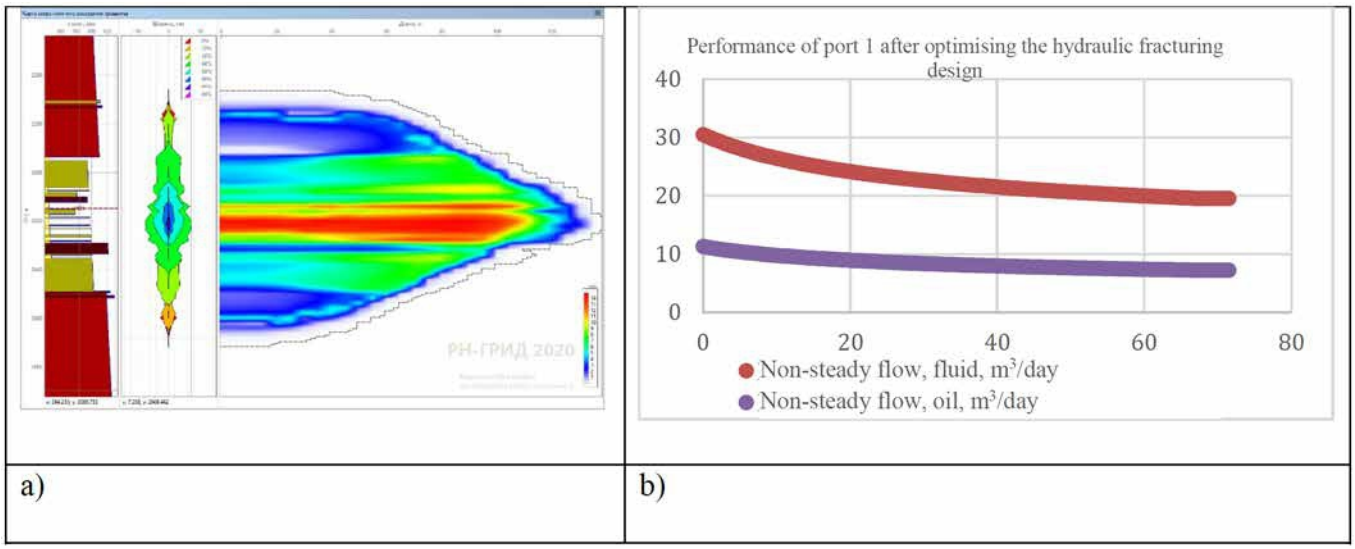

Figure.21—a) The geometry of a port 1 hydraulic fracture after the hydraulic fracturing operation b) Flow rate of port 1 hydraulic fracture

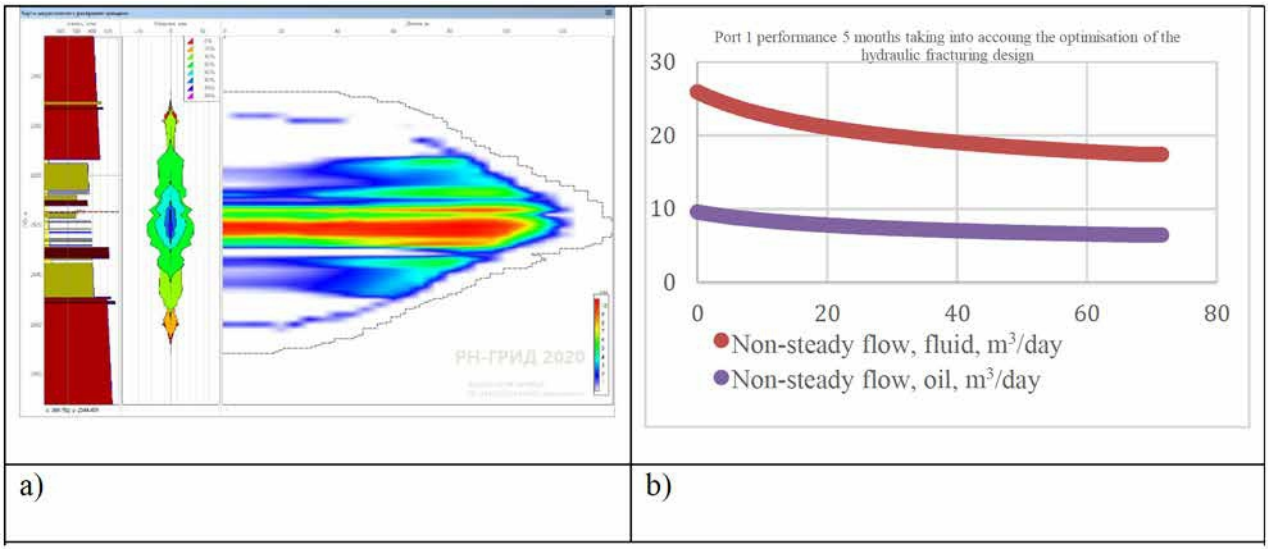

Figure.22—a) The geometry of a port 1 hydraulic fracture after the hydraulic fracturing operation b) Flow rate of port 1 hydraulic fracture

Thus, comparing the results of the hydraulic fracture model calibration, taking into account the crushing and embedment of the proppant, as well as the hydraulic fracturing design optimization, the total increase in oil production for 2 months of well operation is about 1,000 tons.

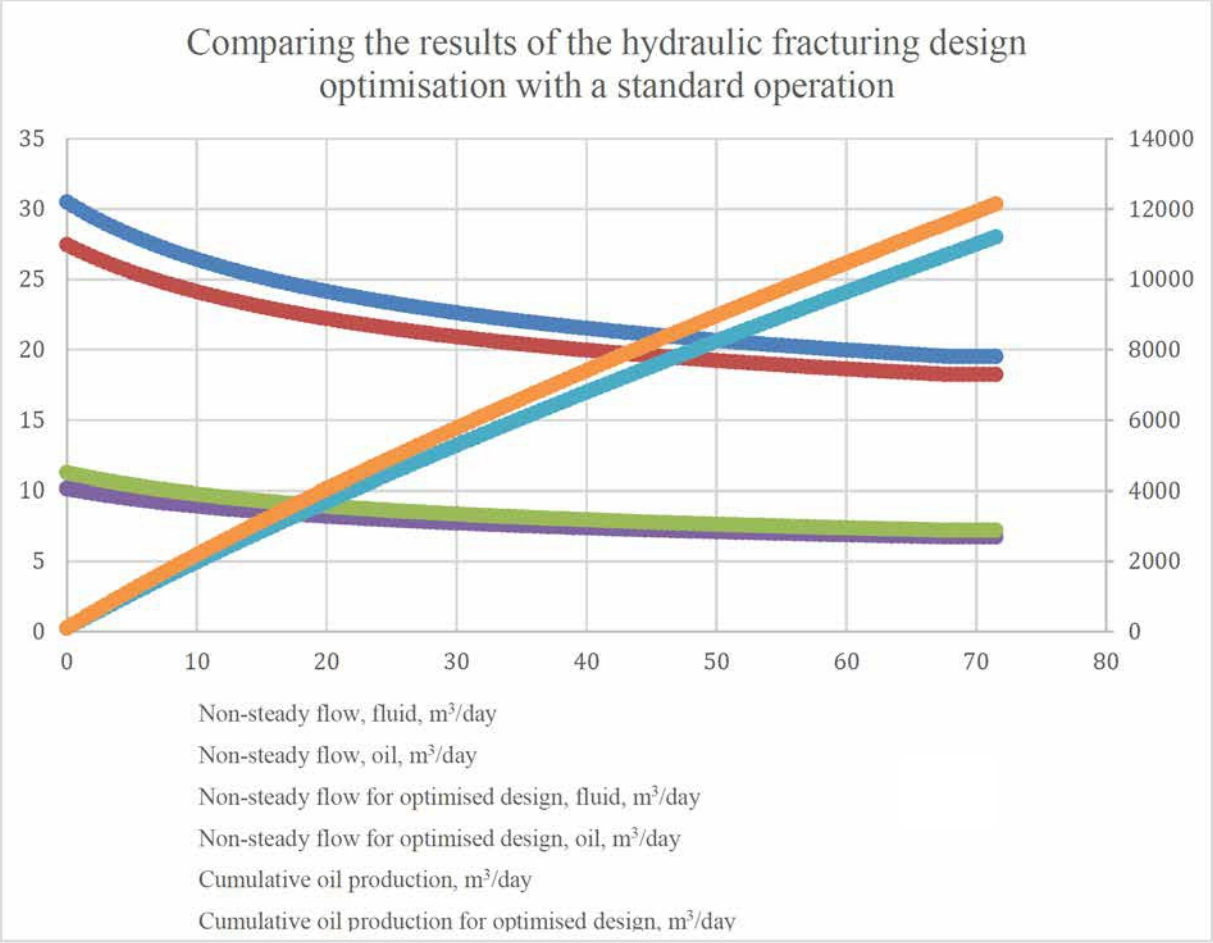

Figure.23—Comparing the results of the hydraulic fracturing design optimization with a standard operation

Conclusion

The case study of a real well, in which two Geosplit marked proppant signatures were injected, demonstrated partial degradation of the hydraulic fracture due to partial crushing and embedment of the proppant.

The dynamics of the change in the marker quantity were used to estimate the change in the hydraulic fracture geometry;

Optimization of the hydraulic fracturing design was proposed, taking into account the effect of the proppant crushing and embedment, to increase the lifetime of the hydraulic fracture and, as a result, a ~ 1000 ton increase in the fracture's flow rate for two months.

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