SPE-208545-MS

An Integrated Approach to Well Logging: The Case of the Bazhenov Formation

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This paper was prepared for presentation at the SPE Eastern Europe Subsurface Conference held in Kyiv, Ukraine, 23 - 24 November 2021.

Abstract

New geological structures – displaced blocks of salt diapirs' overburden – were identified in the axial part of the Dnieper-Donets basin (DDB) beside one of the largest salt domes due to modern high-precision gravity and magnetic surveys and their joint 3D inversion with seismic and well log data.

Superposition of gravity lineaments and wells penetrating Middle and Lower Carboniferous below Permian and Upper Carboniferous sediments in proximity to salt allowed to propose halokinetic model salt overburden displacement, assuming Upper Carboniferous reactivation.

Analogy with rafts and carapaces of the Gulf of Mexico is considered in terms of magnitude of salt-induced deformations.

Density of Carboniferous rocks within the displaced flaps evidence a high probability of hydrocarbon saturation. Possible traps include uplifted parts of the overturned flaps, abutting Upper Carboniferous reservoirs, and underlying Carboniferous sequence. Play elements are analyzed using analogues from the Dnieper-Donets basin and the Gulf of Mexico.

Hydrocarbon reserves of the overturned flaps within the study area are estimated to exceed Q50 (P50) = 150 million cubic meters of oil equivalent.

Introduction

Extraction of unconventional hydrocarbons (HC) is on the agenda for the oil and gas industry, since oil and gas are depletable HC resources, and over time, there is a need to compensate for the decline in production from traditional fields by developing unconventional sources, such as sands, shales, and heavy crude oils.

Unconventional hydrocarbon resources in Russia far exceed the amount of oil and gas that is currently under development. The development of these resources, however, poses some challenges due to the small amount of data, the lack of proven exploration and development technologies, and low economic effect in comparison with conventional hydrocarbons. In addition, exploration and production of such hydrocarbons have a significant disadvantage since conventional and unconventional reservoirs differ dramatically in properties, such as composition, porosity, and permeability. Permeability is a very important parameter because it determines economic viability of hydrocarbon extraction from the pore space of reservoir rocks.

Sixty-seven percent of the hard-to-recover domestic oil is concentrated in the Bazhenov and Tyumen formations, as well as in the Achimov reservoir in the Khanty-Mansi Autonomous Okrug (KhMAO). The deposits of the Bazhenov formation are strategic for Russia. Its reserves can be up to 120 billion tons of oil, which is about five times the size of the Bakken formation in the United States, the initial point of the American shale revolution [9].

The development of Bazhenov formation is one of the activities of Gazprom Neft in the field of unconventional reserves. The Bazhenov formation extends over one million square kilometers. A particular feature, determining the commercial value of this formation, is an abundance of high-quality crude oil. However, due to the low permeability, as well as a small oil- saturated thickness of approximately 10 m, the development of the Bazhenov formation has long remained uneconomical in terms of achieving commercial oil inflows. The most common technology in field development is drilling of horizontal wells with multi-stage hydraulic fracturing (MHF), but in the above case, the technologies applied are also unconventional due to high injection rates, significant amounts of injected fluid, and complex equipment. MHF is used in unconventional reservoirs due to the complex geological structure of the subject field, namely, the presence of natural fracturing zones, abnormally high reservoir pressure, low porosity and permeability, non-uniform distribution of wells with drastically different flow rates across the area, i.e. the presence of hydrocarbon accumulation zones ("sweet spots"), as well as prompt production decline during the year after the MHF operation, etc., are fundamentally different from operations in traditional reservoirs. The use of customised treatment plans for MHF to create a stimulated reservoir volume (SRV) (Figures 1 and 2) or a large half-length fracture involves high- rate injections ($Q \sim 15$ m^3/min) and a large volume of low-viscosity fluid with small-diameter proppants. Such measures are required for initiating and subsequent consolidation of natural fractures, which helps increase the formation drainage area, and, consequently, hydrocarbon recovery multi-fold [1, 2, 5].

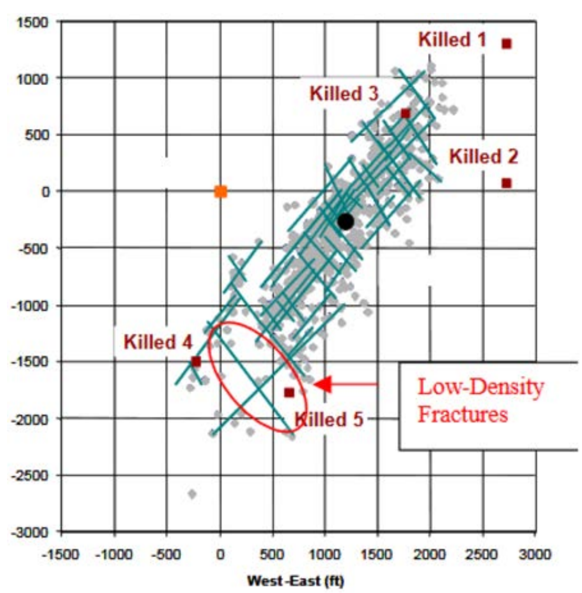

Figure 1—Example of MHF with the development of a SRV that stopped production in neighbouring production wells

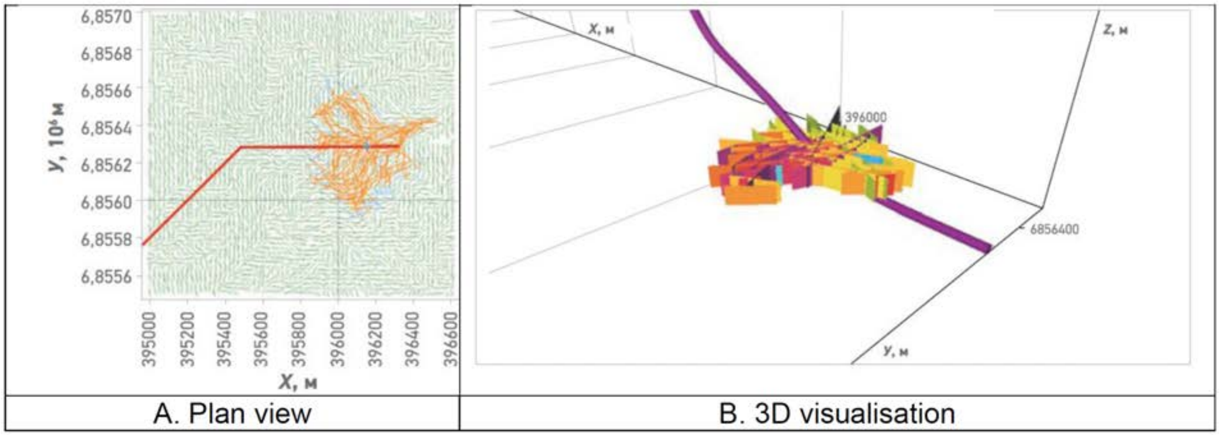

Figure 2—Example of MHF with the development of a SRV for wells of the Bazhenov formation a - plan view; b - 3D visualisation

It also should be noted that in the development of unconventional reservoirs operator companies are in constant pursuit of new technologies that promise a significant increase in efficiency. They should be both energy-efficient and resource-saving, enabling the expansion of economically recoverable reserves and maintaining oil production volumes. These include technologies aimed at improving the design of horizontal wells with MHF, integrated engineering providing the possibility to continuously monitor and analyse well data, the construction of high- tech wells, and others. These are the key areas for the next decade.

Challenges of conventional production logging tools (PLT complex) in unconventional reservoirs

Recent data shows that only about 30% of the entire Bazhenov formation's thickness consists of interlayer rocks containing light oil. The remaining 70% are oil source rocks that remain inaccessible to standard production methods. These rocks are of particular commercial value due to the high oil saturation. Oil source rocks contain high-quality hydrocarbons, light, with low sulfur content and without other harmful impurities; therefore, their primary and advanced processing does not require significant costs. Such hydrocarbons have the following main features:

- non-uniform distribution of wells with a high initial flow rate across the area;
- significant fluctuations in the initial and subsequent flow rates, ranging from several tons to several hundred tons per day;
- an abnormally high reservoir pressure exceeding the hydrostatic pressure by 60%, which indicates, firstly, the presence of significant oil reserves that led to the reservoir fracture and an increase in pressure, and secondly, potentially high oil recovery factors in the case of elastic drive development;
- a significant increase in well flow rates after the MHF;
- a sharp drop in well production: during the year, the flow rate may decrease by an order of magnitude.

The main task, i.e. increasing the well flow rate by multi-stage hydraulic fracturing, may be solved by applying the best international practices. In the usual sense, the Bazhenov formation is not characterised by sufficient porosity or flow, and therefore, the use of a standard MHF, creating large ruptures, is useless here. In this case, the additional inflow will occur only in few dozens of centimeters of the formation around the fractures. Oil can be produced in the Bazhenov formation only through a fracture network, which is a difficult engineering task to perform. In fact, the task is to make a custom-tailored and costly procedure of hydraulic fracturing at Russian shale deposits a standard operation. This can be achieved only by accumulating sufficient experience in conducting MHF with simultaneous monitoring of fractures using modern well logging tools.

Well logging techniques designed for production profiling after hydraulic fracturing and PVT analysis of the fluid can be grouped into three categories:

- Conventional production logging tools (PLT);
- Fiber optic sensors for online monitoring distributed along the entire wellbore (with additional software);
- Marker-based technologies for dynamic production profile surveillance.

Conventional PLT techniques are successfully used in vertical wells and allow for obtaining quite informative data on the performance of interlayers or individual layers. However, when evaluating their effectiveness in horizontal wells, it should be kept in mind that the use of standard PLT equipment with each method represented by a single sensor does not yield a reliable solution for inflow surveillance in horizontal wells and leads to interpretation errors. To make production logging in horizontal wells more efficient, a specialised multi-sensor hardware combo can be used that is capable of solving the tasks set in wells with multiphase flow and stratified flow. The above combo set up involves the use of assemblies of special modules with multi-sensor systems distributed over the wellbore cross-section, as well as relevant technologies conveying tools to the bottom hole [7-9].

Although stationary fiber-optic systems show reliable results in the case of horizontal wells, they are not widely used in non-conventional fields, since this solution is far more expensive in comparison with traditional methods and, in addition, has some engineering downsides, such as risks associated with the equipment run into the well, as well as the need for timely repair and maintenance.

An alternative modern tool that allows for obtaining detailed data from the well bottom is tracer-based production profile surveillance using high-tech materials. This technology provides the possibility to increase the amount and frequency of data stream from the bottom of a horizontal well during field development, used to analyse the long-term dynamics of the performance of a horizontal well's intervals. The method is of particular value if used in the wells of the Bazhenov formation, since a significant increase in the amount of data on the subject field will enable a great stride forward in the study of non-conventional hydrocarbon sources.

Table 1 compares different production logging and production profiling methods.

Table 1—Comparison of the features of conventional PLT and tracer-based production profile surveillance technique (qPL)

Production logging method	Conventional PLT complex using coiled tubing	Marked proppant
Logging period	*Several hours*	*Hydrophilic, oleophilic, and gas — over 3 years (depending on the conditions)*
Well intervention or change in the operating mode are required	*Yes*	*No*
Bench tests	*Yes*	*Yes*
Number of logging operations per year	*1—2*	*6—12 (optional at customer's request)*
Laboratory	*N/A*	*Yes*
Multilateral wells or wells with the bottom hole at a large distance from the vertical	*Yes*	*Yes*
Applicable in cemented liners	*Yes*	*Yes*
Applicable for old/new wells	*Yes*	*Yes*
Applicable in open holes	*Yes (with restrictions)*	*Yes (with restrictions)*
Evaluation of the quality of the bottom-hole zone treatment or hydraulic fracturing	*Yes*	*Yes*
The results can be used to improve the efficiency of field development	*Yes*	*Yes*
Method limitations	*Accessibility of a horizontal wellbore; Risks associated with well interventions;*	*Limited use in high-viscosity oil; depends on the success of the hydraulic fracturing operation*

In addition, the tracer-based technique can help complete a number of related objectives in field development optimisation:

- Development of recommendations for improving well operation efficiency with MHF (oil flow rate, water content);
- Estimation of HC reserves recovery;
- Localisation of remaining mobile reserves;
- Issuing recommendations on changing the well operation parameters;

- Identification of the dynamic characteristics of MHF fractures;
- Providing additional tools for validating data obtained by micro seismic monitoring and well logging;
- Analysis of the field geological structure and the available information on wells with MHF;
- Updating the geological model taking into account new wells with MHF;
- Simulation of the reserves recovery process using pie three-dimensional reservoir models, taking into account the data of each interval's performance;
- Assessment of the feasibility of in-fill drilling according to the dynamic well test data.

Subject well

In September 2018, 16-stage multi-stage hydraulic fracturing was performed at one of the wells in the Bazhenov formation in the IInd petrophysical pack, which involved a high-rate operation with a large volume of injected fluid, the presence of "slug" packs, marked proppant at each treatment stage, and the use of a low-viscosity slickwater fluid at the initial stages of the operation with subsequent transition to high-viscosity systems to enable the transfer of high- concentration proppant and creation of high conductivity in the bottom-hole zone.

The Customer approved conducting an address operation of multi-stage hydraulic fracturing, summarised in Table 2. Figure 4 shows data on the consumption rate, concentration and injection of proppant.

Table 2—Plan of the MHF operation

Stages no.	Consumption rates, m^3/min	V_{fluid}, m^3	M_{prop}, t	40/70	30/50	30/50 (marked)	Injection, concentration kg/m^3
2 – 4	12 – 8	1,200	70	35	20	15	350 – 450
5 – 6	10	1,100	100	40	45	15	150 – 200
7 – 16	10	1,100	100	40	45	15	350 – 450

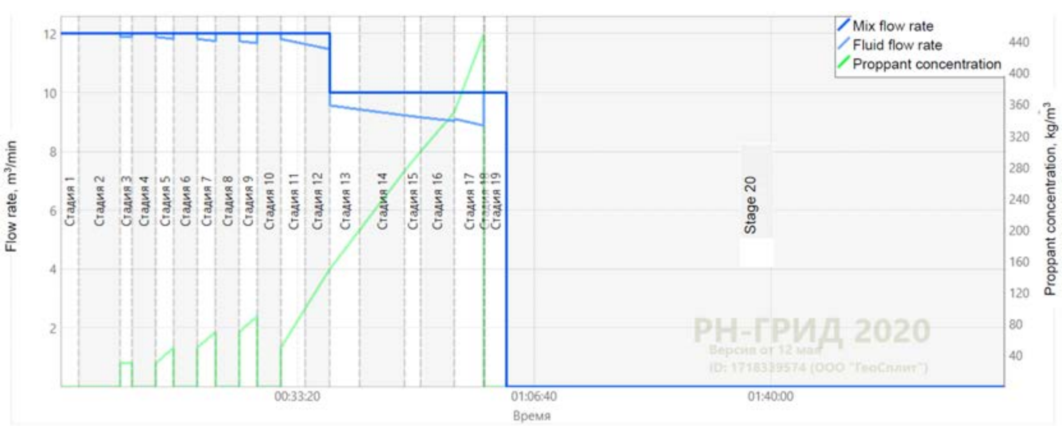

Figure 3—Hydraulic fracturing treatment plan for stages 2-4

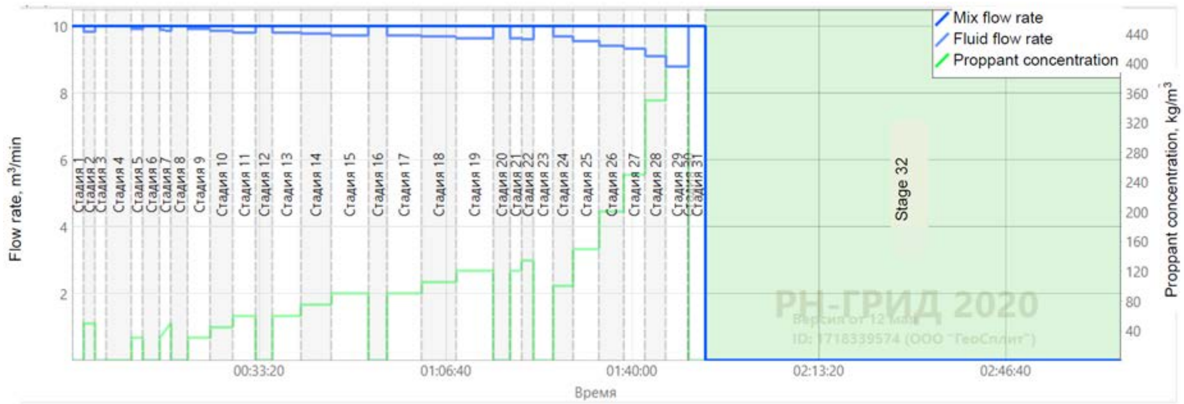

Figure 4—Hydraulic fracturing treatment plan for stages 6-16

The treatment plan for stage 1 involved a 15-ton hydraulic fracturing operation for the purpose of well clean-up and checking the downhole equipment. For this reason, this stage will not be considered in further analysis.

The hydraulic fracture geometry and the proppant location for the actual operation modelled for stages 2-5 are shown in Figure 5. The marked proppant was injected at the last stage of the multi-stage hydraulic fracturing.

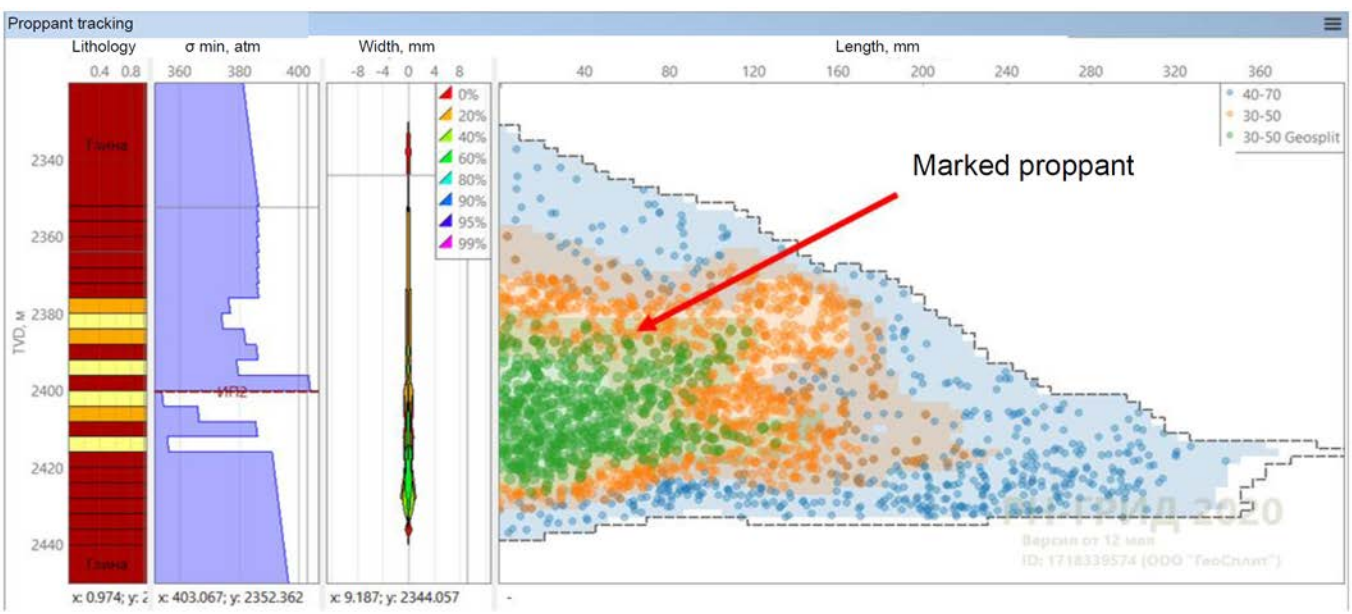

Figure 5—The modelled hydraulic fracture geometry and the proppant location for stage 4

Stages 5 and 6 are shown in Figure 6. In these designs, marked proppant was injected at medium proppant stages, followed by over displacement with a conventional 30/50 ceramic proppant in the amount of 35 tons to push the proppant deeper in order to increase the area of its contact with the formation.

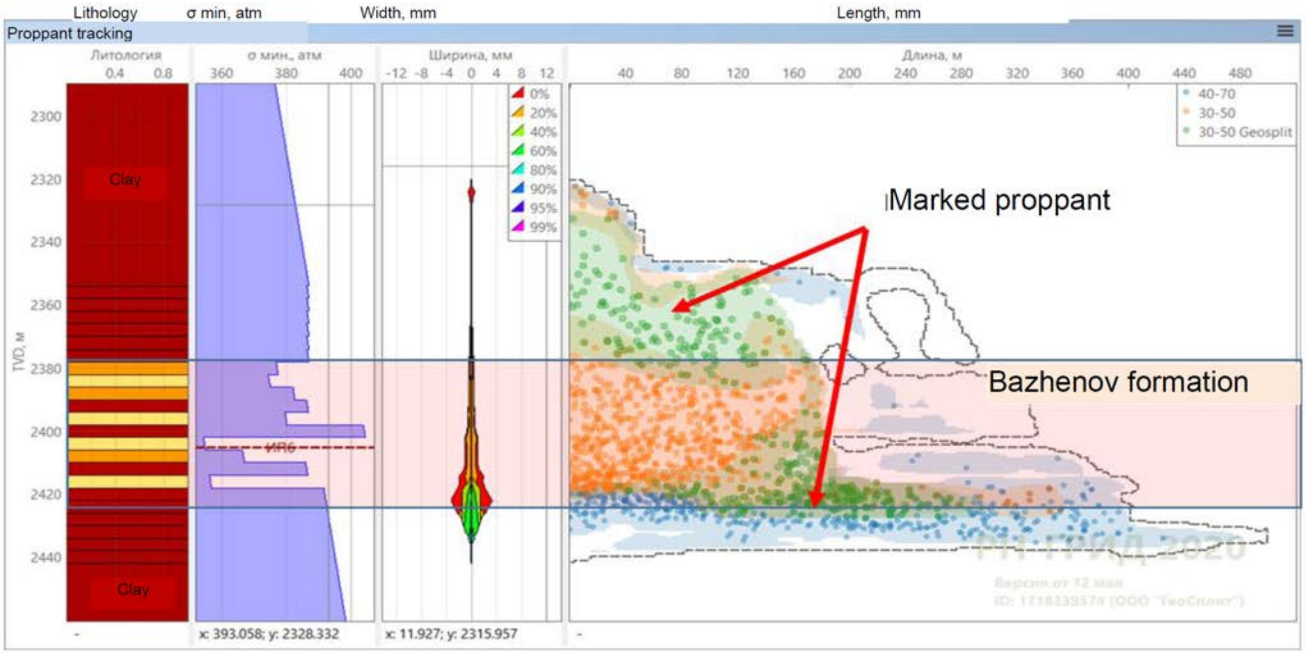

Figure 6—The hydraulic fracture geometry and the proppant location for stages 5 band 6

However, based on the simulation results and matching the actual pressure data with the model values, it was found that some amount of marked proppant is located in the over/underlying impermeable barriers, which affects the quality of tracer-based studies and can lead to significant distortions in the inflow profile assessment.

Stages 7-16 are shown in Figure 7. In these designs, the marked proppant was injected as second last proppant stage, followed by over displacement with 5 tons of ordinary 30/50 proppant. In this type of treatment, marked proppant forms a semi-circular pattern within the boundaries of the development site. Post modelling showed that this arrangement is the best among all treatments conducted.

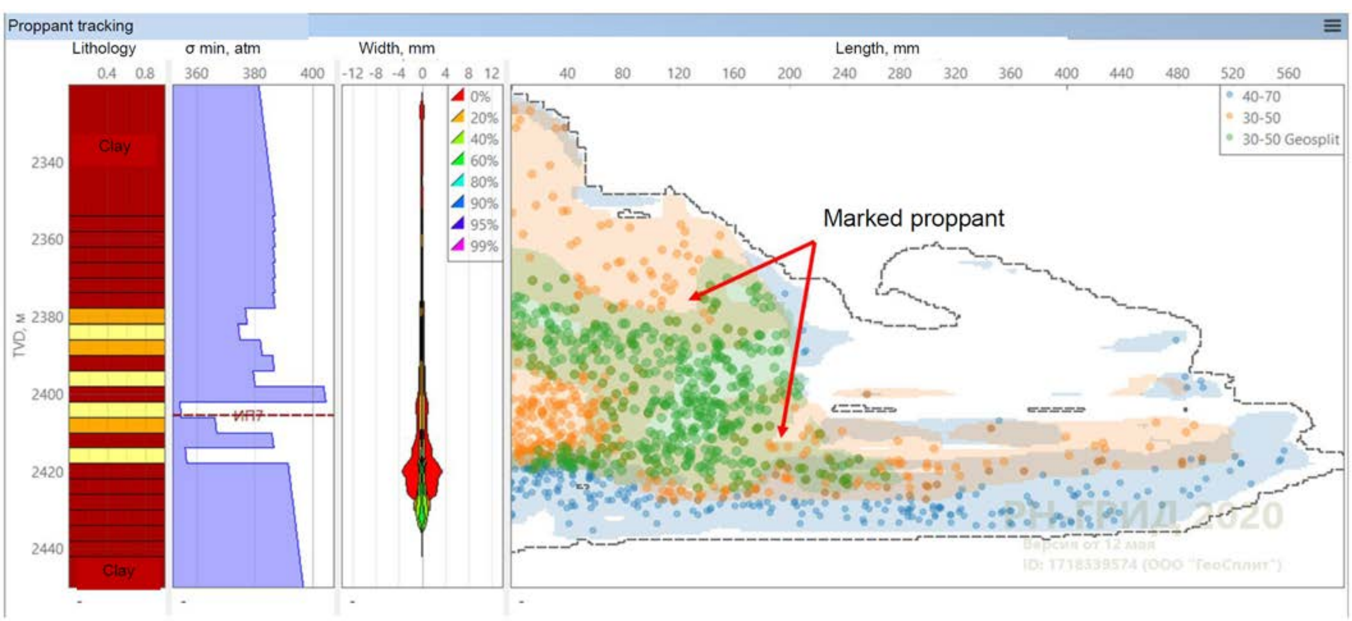

Figure 7—Visualisation of the hydraulic fracture geometry and the placement of the proppant for stage 7

At each stage of multi-stage hydraulic fracturing, an individual signature (unique tracer code) was used to obtain data on the performance of each hydraulic fracture, i.e. the flow rate for each fraction.

Notably, due to the complexity of the Bazhenov formation structure, as well as the restrictions during the MHF operation, the hydraulic fracturing stages were performed with some adjustments made to the approved treatment plan. These changes were made during the main logging operations and aimed to minimise the risk of complications such as premature screen- out, if the maximum treatment pressure was reached (Figure 8). The changes included a decrease in the flow rate of the injected fracturing fluid, a higher/ lower number of "slug" packs, and a decrease in the amount of the injected fluid, etc.

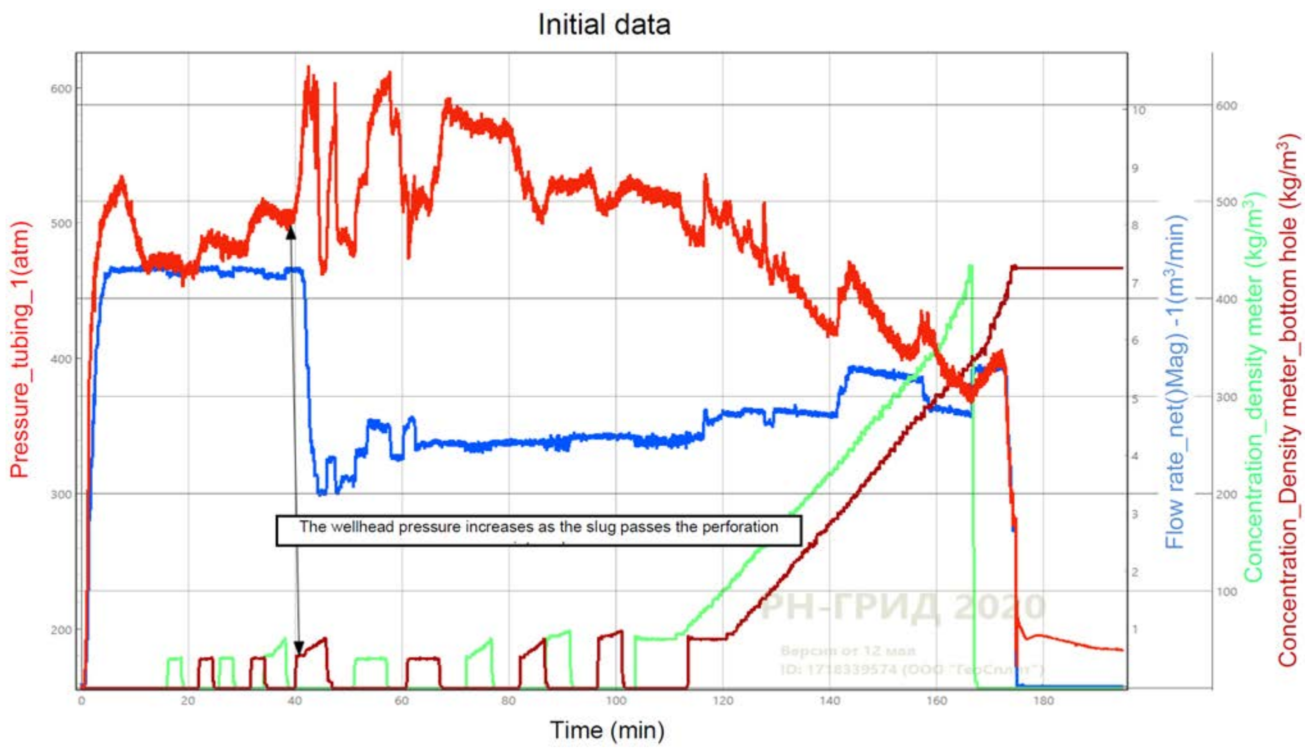

Figure 8—Actual data of stage 1

In general, despite the changes made during selective stimulation of the formation, the field MHF operations were conducted normally, and the entire planned quantity of proppant was injected into the formation.

The well was appended to the reservoir by using the "plug & perf" technique. This technology involves placing sealing plugs and perforation in one RIH/POOH operation. The advantage is that hydraulic fracturing does not require significant resources: only wireline and a frac fleet are required. The perforators and the plug are run-in with a logging cable under the action of gravity in vertical sections and then are pumped by the frac pumps beyond the depth of the planned perforation areas. Then, the wireline set the bridge plug at required depth, correlated with casing collar locator (CCL), followed by shooting perforations. As the multi-stage hydraulic fracturing comes to an end, plugs are drilled at the subject well using coiled tubing.

The marked proppant in the hydraulic fracture, as well as the planned PLT operations, provided an opportunity to evaluate both the well performance as a whole and the performance of individual frac stages. It should be noted that when interpreting the data obtained using both inflow assessment technologies (marked proppant and a standard PLT complex), there are risks of ambiguity in quantifying the flow rate from local points of reservoir fluid inflow. If only one of the methods for inflow estimation is used, the professionals engaged in the development of unconventional reservoirs are faced with many uncertainties.

An integrated approach, on the contrary, yields a more complete picture without distortions, smoothing over the shortcomings of the interpretation of each method.

Tracer-based quantum production logging

For the purpose of tracer-based production logging, 50 samples of reservoir fluid were examined. The logging period exceeded 6 months, during which three tracer-based logging operations were performed — in June, July and November 2019. It should be noted that some of the samples taken in November 2019 do not reflect the actual reservoir production due to long-term downhole operations for cleaning the well bottom using the junk catcher immediately prior to fluid sampling. During the downhole operation, a significant amount of fluid was lost to the formation.

The tracer-based production profile surveillance method involves the placement of marker-reporters containing quantum dots in a polymer cover of proppant. Quantum dots (several nanometers in size) are placed inside insoluble microspheres (marker-reporters one micron in size), then, in turn, the microspheres are incorporated into the polymer cover of ceramic proppant. The marked proppant is added to the bulk of the unmarked proppant and injected as a propping material into the formation during hydraulic fracturing.

The analytical method for identifying marker-reporters is based on a flow cytometry tool [3]. The working principle is as follows: inhomogeneities (in our case, marker-reporters) contained in the sample are lined up strictly one after another using a crimping fluid and a finely tuned hydrodynamic system and then are irradiated with a laser, which leads to their excitation and identification depending on the combination of quantum dots.

Each code corresponds to a certain range of the spectrum that does not overlap with the ranges of other quantum dot combinations in the marker-reporters. Specialised software designed for optical identification of each code can identify them with a high degree of reliability.

When contacting the target reservoir fluid phase during the well operation, the marker- reporters are released from the polymer matrix and washed out by the fluid flow to the surface (Figure 9). Reservoir fluid samples are collected at the wellhead during the subject well operation according to the approved schedule.

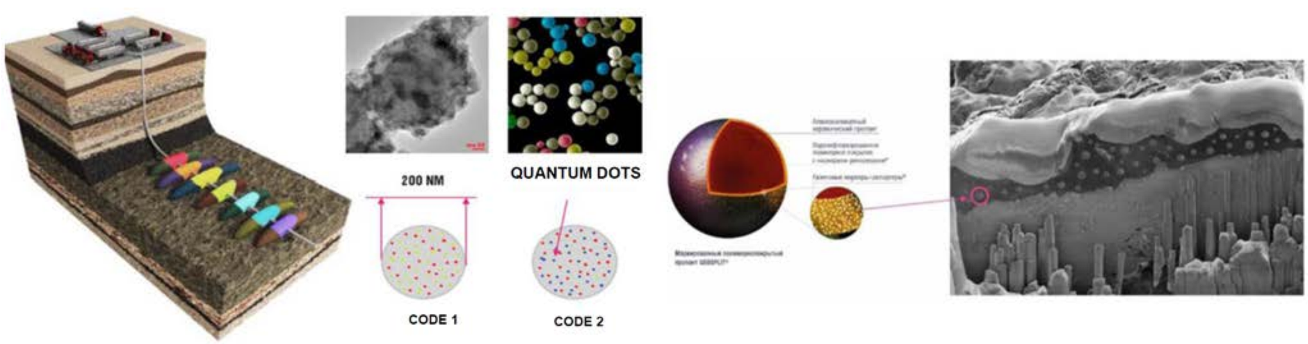

Figure 9—The working principle of the tracer-based production surveillance

After the hydraulic fracturing operation in June 2019, the well was brought into production by the free-flow method due to the abnormally high formation pressure. The well flow rate was maintained by a wellhead adjustable choke. Since August, scheduled downhole pressure gauge pulling-out, plug milling, fishing and emergency operations, etc. have begun at the well. Since the end of October, the well was brought into production again, and preparations were conducted for production logging in November 2019 (Figures 10 and 11).

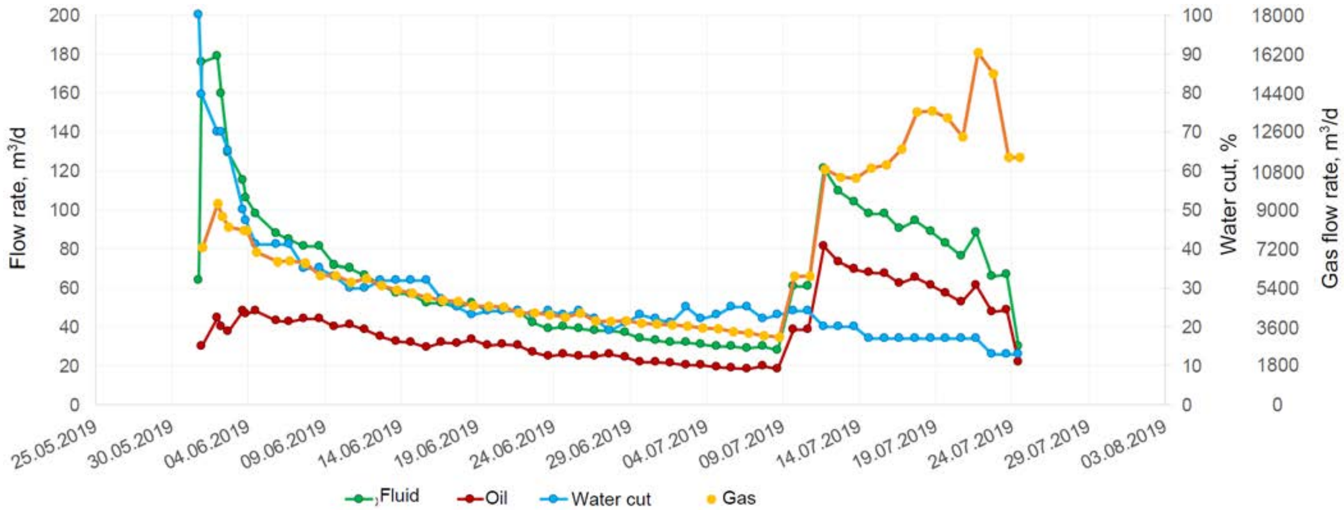

Figure 10—Dynamics of well operation up to shut off for well interventions

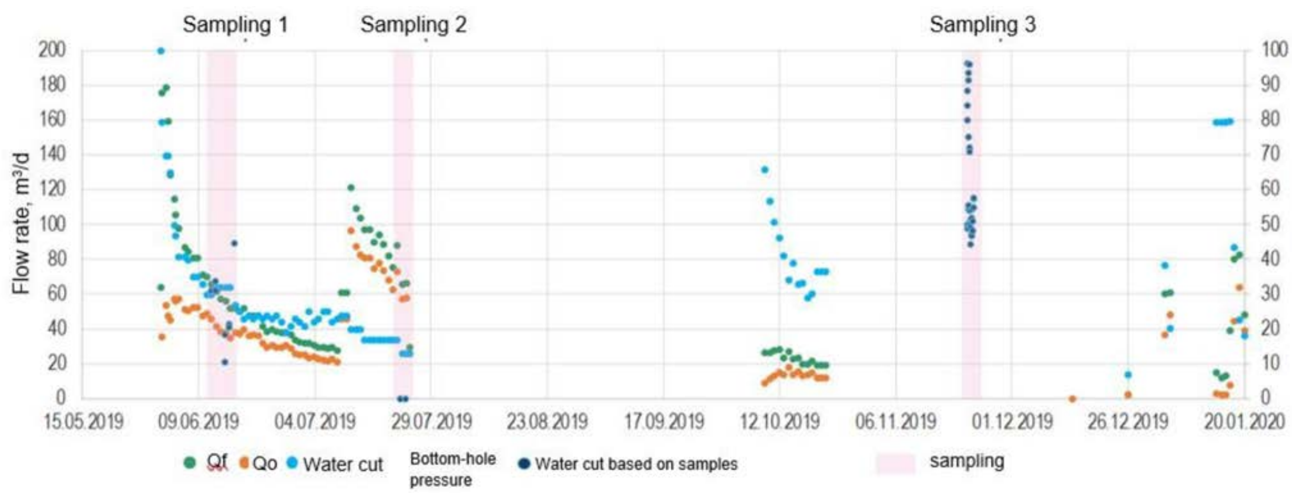

Figure 11—Dynamics of well operation in the period from June 2019 to January 2020

A set of studies was conducted for all reservoir fluid samples taken from the subject well with the aim to extract quantum marker-reporters from the oil and water phases. The analysis of samples and interpretation of the results yielded the relative content of the marker-reporters with different codes, which enabled us to calculate the contribution of each interval as a percentage (Figure 12).

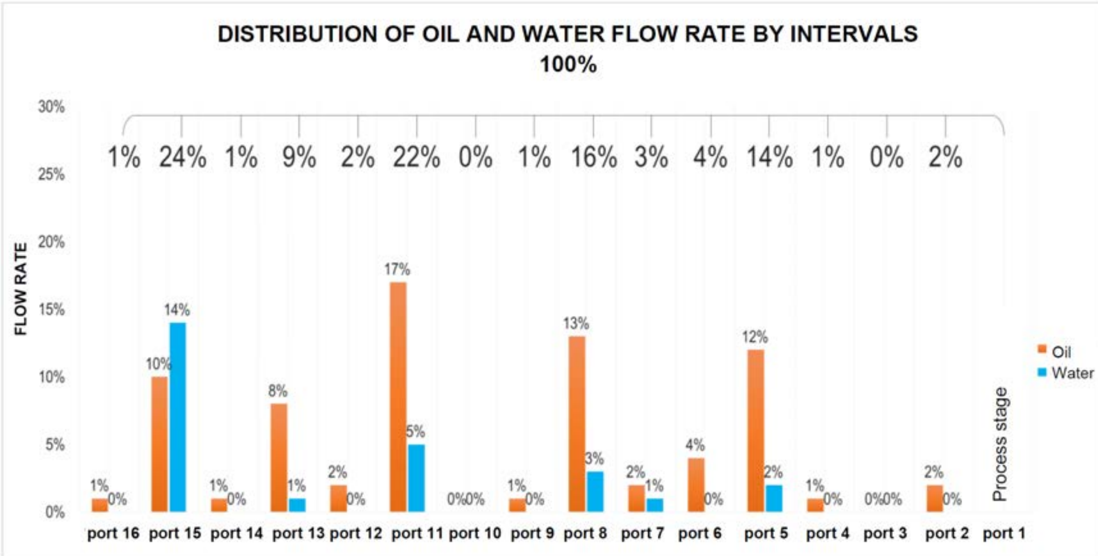

Figure 12—Distribution of oil and water flow rate by stages in the period from June 11, 2019 to June 16, 2019.

The analysis of fluid samples taken in June 2019 showed that stages 5, 8, 11, 13, and 15 differed in the peak oil and water inflow values.

Stages 2, 4, 6, 7, 9, 12, 14, and 16 show the minimum contribution to the well performance, while stages No. 3 and10 are marked as non-contributing.

Based on the results of proppant placement simulation, it was found that at stages 2—4, where the marked proppant was injected at the last stage, marker-reporters are difficult to detect. Most likely, this is due to the lower mass of the used proppant and the injection of a large amount of cross-linked gel (56 out of 70 tons).

At stages 5—6 (Figure 6), the marked proppant was injected at the middle injection stage, which makes a significant contribution to the well performance. A possible reason is the formation of a complex fracture network.

The results of repeated sampling and tracer-based production profile surveillance in July 2019 are shown in Figure 13.

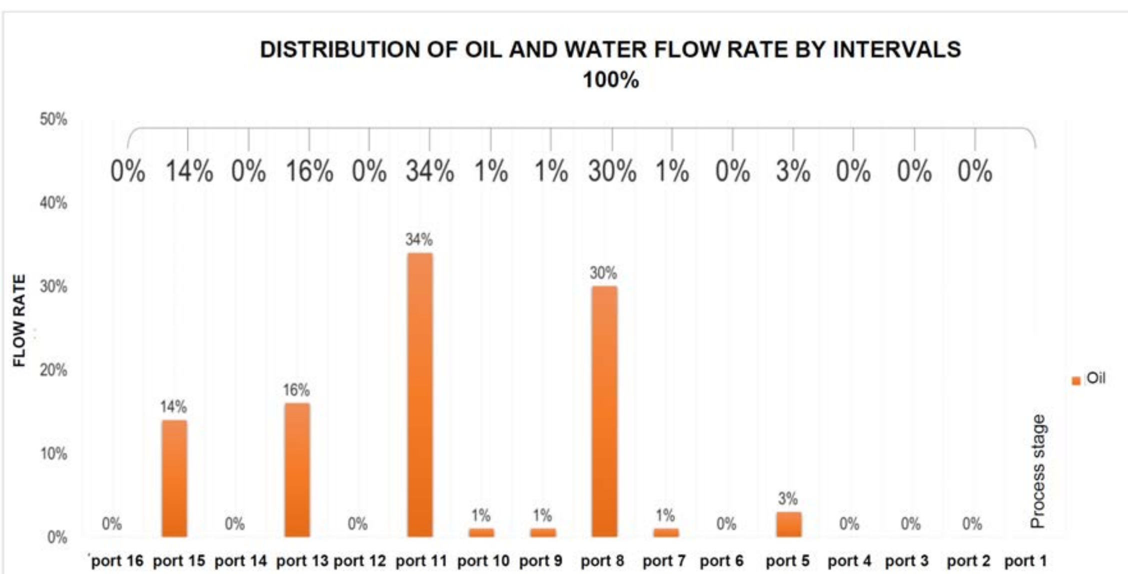

Figure 13—Distribution of oil flow rate by stages in the period from July 22, 2019 to July 23, 2019

The flow rate of port 5 dropped probably due to the placement of proppant in the non-target formation zone, and, as a result, to the lack of fluid flow along the fracture through the marked proppant.

The most positive dynamics of changes in the performance is demonstrated by stage 11, where oil inflow increased to 34% by the first period of logging; stages 15 and 13 also show a small increase in oil flow rate.

The number of stages not contributing to the oil inflow increased to 7 — stages 2, 3, 4, 6, 12, 14, and 16.

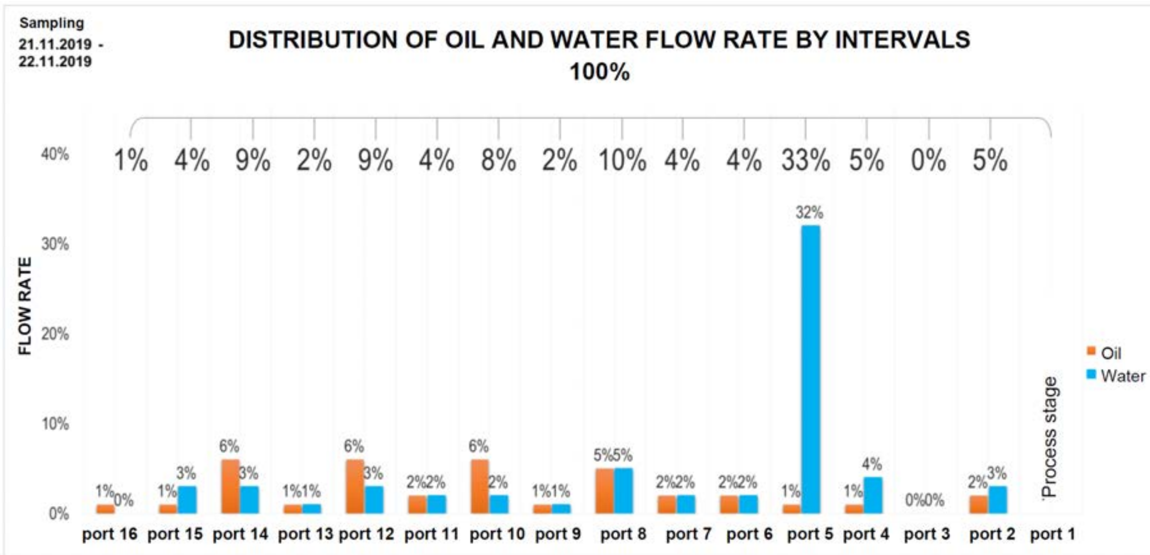

Figure 14—Distribution of oil and water flow rate by stages in the period from November 21, 2019 to November 22, 2019

To assess the dynamics of the intervals' involvement into production for the subject well, the production profile non-uniformity criterion was calculated. This criterion indicates the degree of unevenness of the distribution of interval contributions to the total flow rate of the well at the time of logging. If the interval contributions are distributed uniformly, the criterion takes on a "0" value and is calculated as the standard deviation in the sample of inflow values for the horizontal lateral divided by the arithmetic mean of the sample under study.

During the logging period, the unevenness criterion for the well takes on values from 1.94 to 1.52, which falls within the range of values suggesting that the inflow profile is "uneven". For wells with MHF in low-permeable reservoirs, such values are quite typical; a downward trend indicates a gradual alignment of the inflow profile. According to statistics, multi-stage wells show a more or less aligned profile no earlier than a year after the well is put into production.

Thus, all stages of MHF (with the exception of port 3) showed production in the period from November 21 to November 22, 2019, according to the results of the analysis of the reservoir fluid samples taken from the subject well. The waterflooding is a result of continuous well flushing during the horizontal borehole cleanout using the junk basket in the period from November 12 to November 20, 2019. The high water content in port 5 is most probably the result of the problems that occurred in the well toe and tool sticking.

Conventional PLT

In November 2019, production logging operations (PLT) were also conducted at the well in order to identify the inflow profile and the intervals of behind-the-casing flows, as well as for surveillance of the hydraulic fractures' performance.

The complex of logging operations performed during production using a 6 mm choke revealed the performing intervals of the YK 0 formation, and in addition, a detailed quantitative inflow profile was obtained based on thermodynamic modelling.

As the wellhead measurements data suggest, the total flow rate of the fluid (carbonated oil-water emulsion) is ~45 m ^{3}/day.

According to the data of spectral noise logging during production and the data yielded by the complex of methods, of all hydraulic fracturing ports 2—15 show performance. Logging in frac port 2 was conducted in part. No logging was conducted in frac port 1.

Spectral noise logging revealed the following during production:

- performance is detected in the intervals of the YuK 0 formation that are associated with production in the hydraulic fracs, as indicated by an intense broadband high-amplitude signal on the spectrogram (Figure 18);
- frac port 2, 4, 5, 6, 7, 8, 10, 11, 12, 14, and 15 are characterised by the performance of all perforation intervals;
- perforation intervals of 3,570 —3,572 m (port 13) and 3,775 —3,777 m (port No. 9) show no performance.

Temperature modelling was performed taking into account the amount of the injected fluid at each stage of hydraulic fracturing to analyse temperature disturbances (cooling anomalies) associated with the earlier injected fluid opposite each stage during hydraulic fracturing.

A typical slope is observed between the hydraulic fracturing stages due to thermal convection (Figure 15). The gradient on the thermograms on the inflow between the hydraulic fracturing stages corresponds to the fluid flow rate - a smaller gradient indicates a higher flow rate.

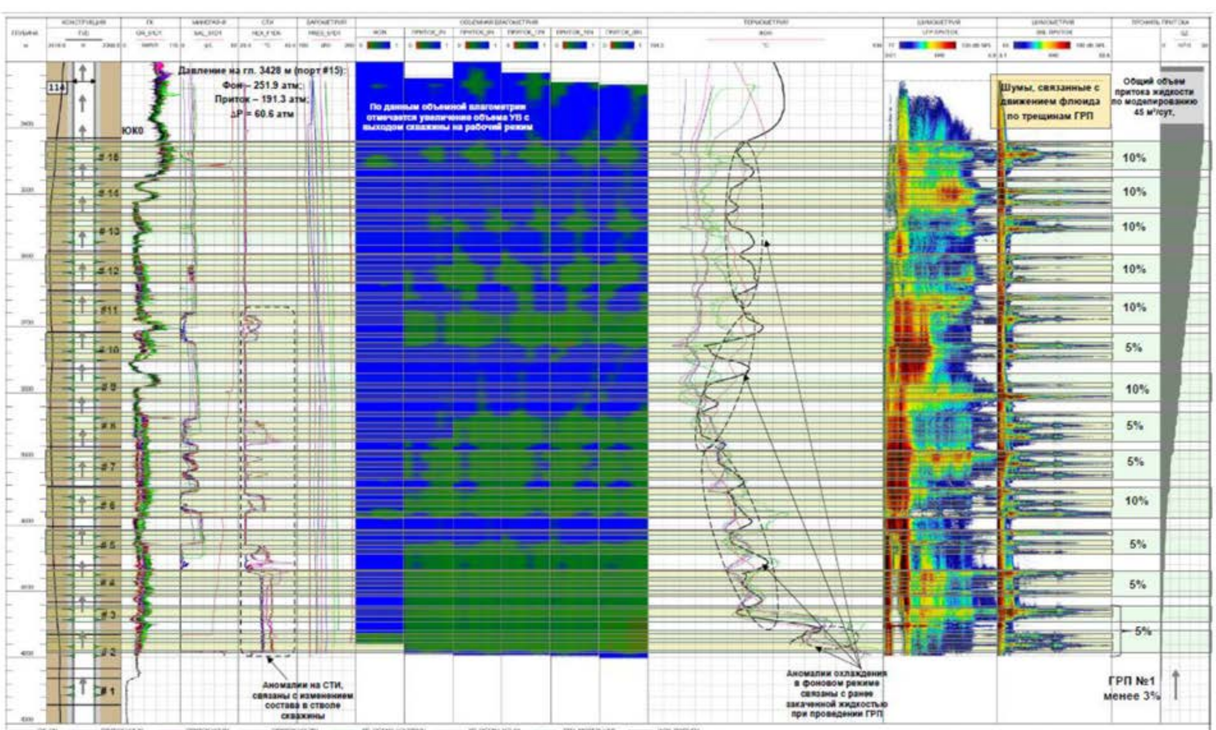

Figure 15—Data of spectral noise logging, high-precision thermometry and thermal modeling in the detailed studies interval

The inflow profile was calculated based on the performed temperature modelling. The following can be noted based on the inflow modelling results (Table 3):

- relatively uniform fluid inflow along the entire wellbore;

- the main fluid inflow comes from the frac ports 6, 9, 11, 12, 13, 14, and 15 (each frac port making 10% of the total inflow);
- ports 4, 5, 7, 8, and 10 show average performance (each frac port making 5% of the total inflow);
- poor performance is observed for ports 2 and 3 (their total contribution to the overall flow rate is estimated at 5%);
- the contribution of port 1 is estimated below 3%.

Table 3—Interval inflow profile for the YuK 0 formation based on the results of thermodynamic modelling and spectral noise logging

Top, m	Bottom, m	Frequency range, kHz	Intensity, dB	Frac port	Type of noise	Inflow profile	
						%	Accuracy, %
3424	3426	3.9 ~ 57.5	67 (High)	15	Fluid flow along the hydraulic fracture	10	5
3439	3442	3.8 ~ 57.7	69 (High)				
3455	3458	3.8 ~ 57.1	65 (High)				
3478	3480	4.1 ~ 57.5	64 (High)	14	Fluid flow along the hydraulic fracture	10	5
3493	3498	3.8 ~ 58.3	73 (High)				
3511	3516	4.0 ~ 58.3	71 (High)				
3534	3538	4.0 ~ 58.3	71 (High)	13	Fluid flow along the hydraulic fracture	10	5
3551	3555	3.9 ~ 58.3	71 (High)				
3594	3597	3.9 ~ 58.1	67 (High)	12	Fluid flow along the hydraulic fracture	10	5
3610	3613	3.8 ~ 38.9	67 (High)				
3628	3631	4.0 ~ 41.0	68 (High)				
3655	3659	4.0 ~ 58.3	70 (High)	11	Fluid flow along the hydraulic fracture	10	5
3672	3675	3.8 ~ 58.2	67 (High)				
3688	3691	3.8 ~ 58.2	67 (High)				
3713	3715	3.8 ~ 20.0	67 (High)	10	Fluid flow along the hydraulic fracture	5	3
3727	3733	3.8 ~ 58.3	71 (High)				
3744	3748	3.9 ~ 58.5	67 (High)				
3787	3791	4.1 ~ 43.0	66 (High)	9	Fluid flow along the hydraulic fracture	10	5
3803	3808	3.9 ~ 58.3	70 (High)				
3831	3834	3.9 ~ 57.2	67 (High)	8	Fluid flow along the hydraulic fracture	5	3
3847	3852	4.0 ~ 58.4	70 (High)				
3864	3868	4.1 ~ 58.3	70 (High)				
3890	3895	3.9 ~ 58.3	68 (High)	7	Fluid flow along the hydraulic fracture	5	3
3905	3910	3.9 ~ 58.3	71 (High)				
3922	3927	3.9 ~ 58.3	68 (High)				
3949	3953	3.8 ~ 51.1	67 (High)	6	Fluid flow along the hydraulic fracture	10	5
3965	3970	3.9 ~ 58.3	68 (High)				
3979	3986	3.9 ~ 58.3	73 (High)				
4010	4014	4.0 ~ 58.3	69 (High)	5	Fluid flow along the hydraulic fracture	5	3
4026	4029	3.8 ~ 48.4	67 (High)				
4040	4043	3.9 ~ 41.9	68 (High)				
4070	4076	4.0 ~ 58.3	71 (High)	4	Fluid flow along the hydraulic fracture	5	3
4087	4090	3.9 ~ 40.9	63 (Medium)				
4100	4104	3.9 ~ 51.5	69 (High)				
4127	4129	4.0 ~ 58.3	74 (High)	3	Fluid flow along the hydraulic fracture	5	3
4133	4135	4.1 ~ 58.3	73 (High)				
4166	4170	3.9 ~ 58.2	69 (High)	2	Fluid flow along the hydraulic fracture		
4180	4184	3.9 ~ 58.3	69 (High)				
Below the analysis interval (frac port 1)						below 3%	-

Results of comparing tracer-based quantum production logging and the PLT complex

- For most of the subject well intervals, there is a convergence of the qualitative data obtained by the tracer-based method and the results of PLT interpretation involving spectral noise logging (Table 4);
- The discrepancy is observed in the assessment of the stage 5 contribution.

Table 4—Comparison of the results of PLT and tracer-based qPL technologies

Frac stage No.	Frac sleev interval, m	Flow rate (PLT), %	Flow rate (Noise logging), %	Flow rate %		
16	3428-3446	14%	10%	1%	0%	1%
15	3482-3500	28%	10%	24%	14%	4%
14	3538-3556		10%	1%	0%	9%
13	3600-3616	8%	10%	9%	16%	2%
12	3659-3677	21%	10%	2%	0%	9%
11	3721-3737		5%	22%	34%	4%
10	3775-3793	15%	10%	0%	1%	8%
9	3835-3853		5%	1%	1%	2%
8	3894-3912		5%	16%	30%	10%
7	3954-3972	4%	10%	3%	1%	4%
6	4013-4031		5%	4%	0%	4%
5	4072-4090	10%	5%	14%	3%	33%
4	4124-4142		5%	1%	0%	5%
3	4180,7-4196,7			0%	0%	0%
2	4242-4256		0%	2%	0%	5%
1	Process stage	0%	0%	0%	0%	0%

This discrepancy between the results yielded by the tracer based method and the PLT for port 5 could possibly be a result of well interventions during the PLT works and fluid sampling.

To confirm that the proppant placed in stage 5 has just the same tracer release rate as the proppant in other stages, the degree of a marker-reporter wash-out rate was compared using reference proppant sample specimens. Additionally, the reference proppant specimens taken in the field after the multi-stage hydraulic fracturing were examined to establish whether marked proppant had been injected in a correct way as per the approved work programme.

Besides, the data obtained are used for training and calibration of the simulation model as part of a special analytical system.

The procedure for checking reference specimens for the interval in question (port 5) consisted of the following stages:

1. The reference specimens of code 4 proppant (port 5) were used to prepare unified samples for further analysis in a flow cytofluorimeter.
2. The flow cytometry data was used to compare the quality of the marker code found in the aliquot with the one indicated in the description of the reference specimens and the work programme.

3. When the signature number of a certain reference sample directly matched one in the list specified in the work programme, machine learning algorithms were configured and calibrated.
4. Machine learning algorithms were used for qualitative and quantitative assessment of the properties of reference proppant specimens.

Further on, when analysing reservoir fluid samples, an adjusted mathematical model was used, built on the basis of reference specimens, which helped compensate for possible calculation errors.

Thus, we managed to obtain the most objective and accurate data when analysing real samples, as well as to confirm the degree of marker release under specified conditions (well production during logging).

Conclusion

Tracer-based quantum production logging can be an alternative to the conventional PLT methods. In contrast to conventional production logging methods for horizontal wells, tracer- based quantum production logging with the use of marked proppant does not require any special means of conveying tools and is not associated with the risks of equipment getting stuck downhole or ambiguity in the interpretation of the results obtained in the case of a multy-phase flow in a horizontal well.

Comparison of the data obtained by tracer-based logging and PLT complex revealed a satisfactory convergence for the inflows coming from the frac ports. Both in the case of the PLT complex, and tracer-based logging, a uniform inflow profile is observed for all ports after several months of production. It is important to mention that it would be very difficult to obtain a reliable result using exclusively conventional production logging technologies. In the case above, integration of several methods enabled obtaining data on the performance distribution among all hydraulic fracturing intervals along the horizontal well in question. And on top of that, the component composition of the extracted fluid was identified for each interval, so non-contributing ports were detected. Also, the dynamic assessment of the inflow profile showed a slight discrepancy in the performance of the intervals, if compared with the PLT data. Is was established that such discrepancy occurred due to a number of historical events that took place during the well operation, which proves the value of integrated logging in complex conditions with a low unstable inflow. Nevertheless, investigation into the causes of the possible divergence of logging results obtained by different methods is still a matter of ongoing continuous work. Since the statistical sample is small, it is recommended that the technology be implemented in subsequent wells and bench-tested under the P-T conditions to eliminate possible uncertainties in subsequent studies. The results of this work can be potentially applied for assessing the reserves recovery of the reservoir area, based on the accumulated average daily production for all ports, as well as for a decision support system in terms of planning further well interventions, including selective stimulation of the target reservoir at a higher level.

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