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Undiscovered DTS potential of horizontal well inflow profile monitoring

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Distributed temperature sensors have several important advantages. They enable to obtain on-line information about well conditions and the frequency of measurements is greatly higher than traditional PL on wireline or coil-tubing. Addition- ally the price of multisensor PL in horizontal well with low oil rate is extremely high.

Interpretation methods of such data, which are wide spread in literature, do not allow realizing informative potential of DTS technology completely. Interpretation models that are used contain a lot of input parameters and can't be considered ef- fective in case of limited volume of data.

The authors conducted mathematical modeling of heat and mass transfer in horizontal well and carried out several DTS measurements in vertical multilayered well. It showed that transient processes in start-up and shutdown conditions contain information about inflow profile. This information is of high value because it has a very low dependence on temperature properties of the formations and fluid. In the author's opinion the development of such methods and measurements technologies is the matter of nearest future.

From the point of view of development control horizontal well is one of the most complicated research areas. Even conventional maintenance of a vertical wellbore introduces some limitations to traditional production logging methods (PLT- Production Logging Tool) [1-4]. Accuracy of traditional approach to marginal multiphase flow metering by means of mechanical flow meter still remains uncertain and unsuitable for well applications. Under certain conditions, such as incomplete liquid carry -over when the liquid accumulates in the wellbore, fluid identification methods are capable of determining composition of liquid phases rather than fluid distributions. In complex multiphase flow dynamics data obtained with the measurement methods depend on many factors: location of sensors in the wellbore, wellbore inclination, etc.

Wellbore conditions have a large effect on the quality of the data obtained with PLT. In horizontal flow, liquid have a tendency to flow in separate, stratified layers at different velocities. Non-uniformity of the liquid velocity distribution increases water or gas holdups inside the wellbore. Logging problems typically occur when uncemented filter run in the wellbore influences on flow behavior and part of the inflow which moves along the casing annulus can not be detected by sensors. This inflow may occur at any spot along the whole length of the wellbore making accurate determination of fluid entry intervals very complicated.

In horizontal well, conventional production-logging tools are often inadequate and give misleading results. So the need to understand and measure fluid flow within complex flow regimes became increasingly important and necessitated the development of alternative techniques and new tools. This paper will address to the flow metering challenges and introduce a new approach to monitoring inflow profile in the well.

Advances and benefits of new production logging (PLT)

Today the new generation PL technologies are based on combination of conventional flow metering methods using multiple sensors and non-standard technologies, such as optical sensors, inflow tracer technologies, various radiometric methods, scanner tools, etc. Often, several logging methods are run simultaneously and the combination of results is more informative than each individual measurement. These tools provide valuable data about flow profile and composition of fluid in the horizontal well. Combination of various logging methods in a single setup has been extensively practiced by oil companies abroad [3-5], which wasn't largely employed in Russia. Simple modifications of logging tools with multiple sensors that are used by Russian service companies do not provide any reliable data.

Most of the identification challenges connected to inflow profile and fluid composition in horizontal wells can be addressed with the existing technologies. However, such measurement practices are also associated with some specific difficulties. Many Russian fields tend to be located in very remote areas with very limited infrastructure, away from processing facilities. Russia has plenty of "tight reservoirs" (which are found in low porosity and permeability) and therefore a reduced economic margin. Under these conditions, the repertoire of technological tools to support well completion is directly dependent on their cost.

Well compression and swabbing are among the most commonly used conventional PL methods. But these methods are frequently helpless for horizontal wells, especially those that feature low porosity and permeability values. According to standard practice only ESP (electrical submersible pump) Y-tool systems and to some extent powerful jet pumps are proved to provide stable and accurate control of inflow profile and well draw-down. Employment of Y-tool systems, its installation and reinstallation averages nearly 30% of the total PL cost. But it shall be noted, that most of such bypass systems impose strict limitations to internal cross-section for the running tool, ranging from 32 to 45 mm. A high risk of harming the tools occurs during landing them in a bottom hole. Taking into account technical condition of horizontal wells in Russia, the use of slotted reperforation filters and well tractors also affects an increased risk of damage to well integrity. Coiled tubing can be considered one of the most efficient methods, providing secure positioning at a certain depth in the hole. Deployment of coiled tubing equipment takes another 40 % of the PL system cost that includes flow profile and fluid composition interpretation algorithms. Cost of logging operation is about 30 % of the total PL cost.

Some reported cases of applying the listed technical solutions in horizontal wells potentiated real-time measurement of inflow profile and identification of fluid composition and were carried out under nearly operating conditions. However, in contrast to a true value of this knowledge such logging methods are only capable to provide data about particular condition of well-reservoir system registered during a short period of time. In practice, even if an organization tries to reduce maintenance costs by occasional monitoring, such complex and expensive survey still has no economic viability. So far 2-3 surveys of that kind can cost as much as drilling a new well. Therefore, it is reasonable to conclude that this approach can not ensure continuous monitoring of the essential components in a horizontal well.

Although there's no denying the true value of full and qualified set of production logging testings in a horizontal well, but it must be admitted that this method allows covering neither sufficient amount of wells, nor required measurement interval. According to operating conditions of Russian fields, excluding offshore, a test system shall as far as feasible comprise not expensive PLs, ensuring efficient decision-making and problem-solving techniques and permanent control of the field. Temperature survey is seen as pivotal element included to the set of production logging. Temperature measurement, if organized properly, provides very valuable data [1, 2, 5]. But temperature logs can be difficult to interpret because multiple-phase flow results in large amounts of data and some of them may be conflicting.

Analytical algorithms can assist with interpretation of transient processes (i.e. which occur due to changes in well operation mode, during shutdown and launching) and optimization of measurement accuracy. But duration of such temperature measurements is usually short and takes about a few tens of minutes. In these conditions, only stationary monitoring with distributed temperature sensors along the entire depth of the wellbore can provide reasonable data. The desired performance can be achieved with fiber optic DTS and a bunch of distributed temperature sensors integrated into a single communication network.

Fiber-optic distributed temperature sensing

Today the use of optical fibers integrated in distributed temperature sensors have proved to provide an affordable, proven and reliable means of continuous monitoring to a large amount of industrial applications [3,4]. Among advanced applications of optical fibers in well monitoring are seismoacoustic sensors, stress and deformation sensors. Specifically in some cases different types of monitoring systems can use one and the same cable integrated with several optical fibers to significantly expand the range of sensing data.

Fiber-optic based permanent systems for well monitoring have the following main advantages:

1. All parameters are registered along the whole depth of a wellbore with spatial resolution of 0.2 m and more.
2. Prompt communication of data to remote control rooms. Optical fiber can be both used sensor and as a medium for communication and networking.

The main disadvantage of fiber optic DTS is the lack of measurement accuracy. Usually a system margin can be confused with measurement uncertainty of 0.1°C, while conventional sensors are evaluated to have 0.01°C and less. Optical fibers performance parameters and reliability can be significantly improved by use of hybrid cable with electrical conductor, where one end is connected to a standard measurement unit, partially compensating uncertainty of fiber optic sensing.

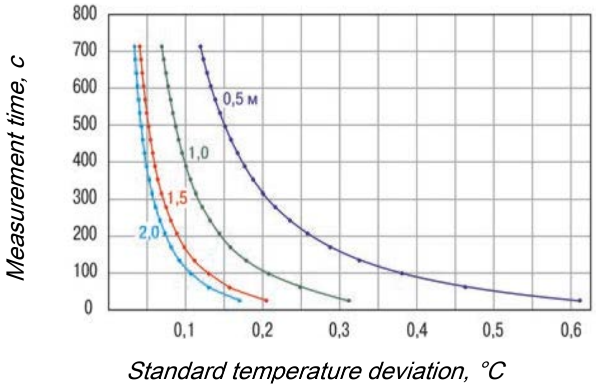


Fig.1 Correlation between standard temperature deviation and measurement time.
The value by each curve corresponds to spatial resolution.

Measurement parameters, such as uncertainty, spatial resolution and measurement interval are also dependent on final settings selected by the user. The graph above corresponds to local characteristic of fiber-optic system by “Laser Solutions”, CJSC and is given as an example (Fig.1). An engineer shall be responsible for selecting settings for the measuring system based on specific needs and conditions of the monitored well.

Installation of permanent downhole fiber-optic sensing system is relatively cost effective compared to the above mentioned surface PL and even lower. As the most expensive part of the installation cost is control station, the quantity of wells controlled by one station can be increased to minimize monitoring costs.

It should be noted that the described technology shouldn’t be considered as a cure-all solution for well control. Nevertheless, a relatively new monitoring technique based on distributed sensors creates totally new opportunities for well surveys, including continuous monitoring, which provides comprehensive data about functionality of the well under pumped conditions. But there are still open questions about informativity of this method, as well as processing and analysis tools dealing with abundant numbers of data. Several tendencies of data processing and data analysis now prevail. One of them is representation of data by identification of temperature curves over a certain time interval, or by visualization of three-dimensional (3D) temperature distributions (three spatial coordinates: depth-temperature-time). Another method is visual analysis of three-dimensional field, which includes conventional techniques used to monitor vertical wells that have been adapted for use in horizontal wells. And the next one is based on modeling of heat and mass transfer processes through physical-mathematical model [6]. At a first glance, the latter method seems to be the best compromise. However, in spite of the fact that such approach was consistently introduced as one of the most promising technologies for geophysical applications and downhole temperature logging, yet it hasn’t become a part of frequent practice.

Since this model will involve multiple unknown parameters even at first approximation, the inverse modeling results have proved controversial. To solve this problem efficiently most of the measurable parameters should be identified in advance. At the same time, in practice an engineer has to implicit some assumptions, which influence on the subjective interpretation of results.

The use of so called ”proactive” technological tools seems to be more realistic. These tools are optimized to build specific environment in a well, in which it is easier to distinguish the studied effect and describe it with a minimum number of most valuable parameters. Distributed temperature sensors provide the most congenial environment for research with proactive technologies. In particular, this method is an established tool to study dynamic processes in a well even in the incipient stages of research.

Informativity of non-stationary processes

Distributed sensors using fiber-optic temperature logging technologies offer unique measurement capabilities with a time-resolved high resolution. Transient processes taking place during operational changes give potentially useful data, that isn’t available during steady-state operation. During steady-state conditions the flow, pressures, etc. in the well are more or less constant over time. During transient conditions, these variables may change rapidly. Early transient processes are formed due to inflow injection through the reservoir into the wellbore and calometric mixing as fluids move along the wellbore. At this stage environmental interaction effects (casing string and formations) with the fluid are minimized. Apparently, understanding nature of transient processes during well startup or shutdown, which usually last for nearly tens minutes, contain information about inflow profile. The ability of fiber-optic temperature sensors to collect temperature profiles rapidly allows is likely very probable for realizing informative potential of distributed temperature sensing (DTS).

This idea has been supported by an express-analysis based on numerical model of heat transfer processes in horizontal well conducted by authors of this paper. Consider the distinctive feature of transient process (Fig.2) in contecst of calculating temperature profile during start-up of horizontal well with multistage hydraulic fracturing (MHF).
In 125, 500, 1000 seconds after start-up of the well, perturbation arising from the fluid injection across the wellbore can be clearly observed, provided that velocity of perturbation front doesn’t depend on fluid composition and ambient conditions. This creates opportunities for evaluation of inflow characteristics of each horizontal well with MHF solely based on the value of well radius.

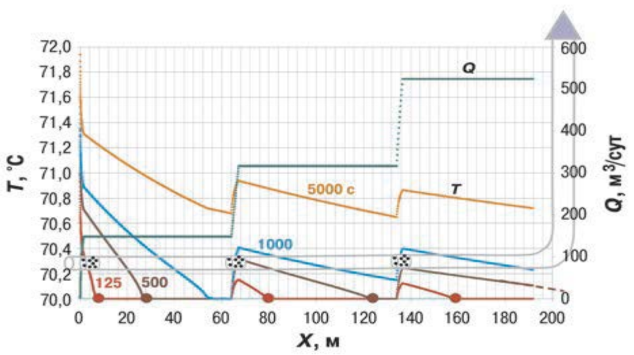


Fig.2 Calculation of temperature profile during start-up of horizontal well with multistage hydraulic fracturing (Q- flow rate of the well, T-temperature) The value by each curve corresponds to time since launch.

Case study

The benefits provided by informationally rich technological method described in this paper can be illustrated by experiments that were carried out by «Laser Solutions», CJSC and «Gazpromneft - Noyabrskneftegazgeofizika» JSC in support of this technique. A vertical well, penetrating two formations has been measured with multiple equipment comprising of distributed fiber-optic temperature sensing system (DTS) and fiber-optic acoustic sensing system (DAS), connected to specialty geophysical fiber-optic sensing cable with a power conductor linked to a standard measuring unit at the cable end. For a better understanding it must be emphasized that compression (hereinafter referred to as azotizing) in low-permeability reservoirs yields weakly unstable flow regime. For the current study, intensity of the flow was too low to be accurately detected by mechanical flow meter. The flow velocity was lower than response threshold, which didn't allow for intensity-based flow tracking and accessing functionality of both reservoirs. However, unstable operation of the well and occasionally pulsating inflow enabled to partially demonstrate key performance capabilities of permanent temperature monitoring with DTS.

In order to illustrate these capabilities temperature curves corresponding to certain time intervals have been selected out the arrayed data. If the cable had been measured with temperature sensor then temperature curves would have been close to profiles, shown on Fig.3.

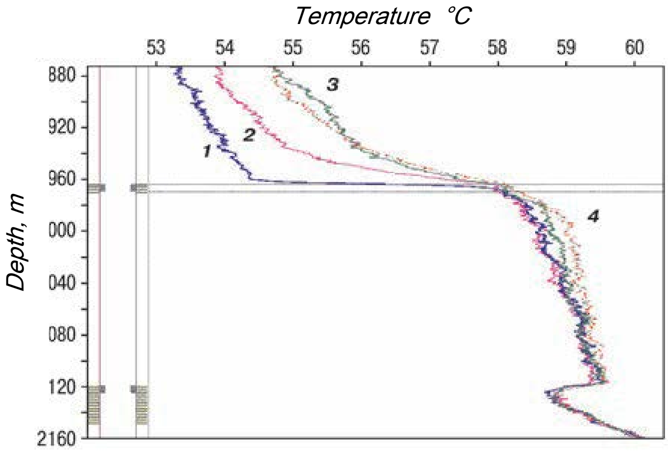


Fig.3. Temperature curves, recorded by fiber-optic temperature sensor during well compression:
1 – Temperature at start of compression with regression to reservoir; 2- background temperature; 3- temperature at actuation of gas-lift valve; 4- temperature of pressure relief

Fig.3 is a graphical representation of each one curve out of many background curves, curves for nitrogen injection regime, for actuation of gas-lift valves and pressure relief. Generally this conventional approach enables to meet the defined objectives and distributed fiber-optic temperature sensing doesn't show a serious priority over temperature gauge with one sensor. On the other hand, the given example is helpful for distinguishing important and potentially valuable information effects.

If we take the advantage of fiber-optic temperature sensing and build temperature curves with lower time intervals, which correspond to transient processes, it will cause an increase and distribution of temperature anomalies. It can be observed on Fig.4, *a* how fluid is injected into reservoir during nitrogen injection (direction of curve displacement is shown with an arrow. A similar effect is shown on Fig 4, *b*, where temperature changes due to actuation of gas-lift valves and start-up of the well, forming the thermal field. Although, here the anomalous temperature processes are observed as positively and naturally growing. Such representation of sampling curves indicates that transient processes, which can be visualized only by fiber-optic temperature logging system provide a great informativity potential about flow rate and fluid composition in the well, unlike traditional temperature logging.

Behavior of temperature curves as a function of time is usually of concern when evaluating various approaches to flow rate calculation. A flow rate can be estimated based on the analysis of wavefront speed at which the disturbance moves through the wellbore. Another realistic method involves modeling a linear relationship between applied stress, driven by density anomaly and flow rate. However, in the lack of initial data for calculating (e.g. thermal properties of fluid and environment), there's a risk of obtaining widely varying results due to maximum possible variability of unknown parameters. Such approach has been validated and widely adopted by the authors within other logging applications [1].

Thus, following the specific methodology will help evaluators apply good practice to unlock the undiscovered resource potential of distributed fiber-optic temperature sensors, which encompass the following considerations:

1. Forming mathematical modeling of typical inflow distributions in horizontal wellbore by applying:

- identified informational effects, that can be analyzed;

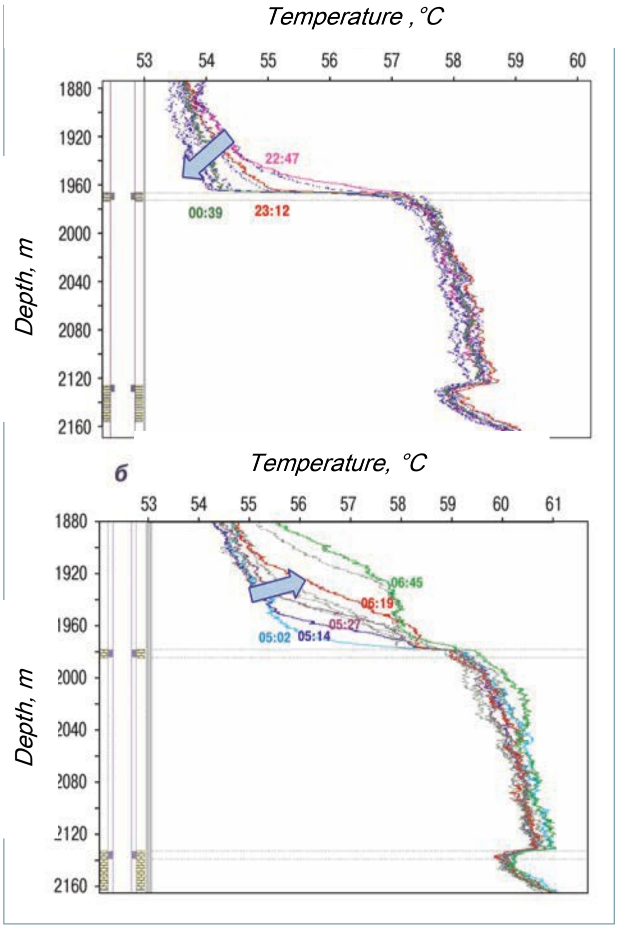
- the most affecting parameters;

- identified requirements to instrumentation and settings of the measuring system based on temperature anomalies.

2. Developing research program that will help to obtain maximum possible amplitudes out of non-stationary effects and indentify them in real conditions, especially in horizontal wells.

3. Developing approaches to interpretation of data obtained by fiber-optic logging, in particular in the lack of relevant initial reservoir data.

The on-site validation of DTS can be initiated in some especially interesting vertical wells when the necessary methodological preparation, as well as informativity limits and suitability of distributed fiber-optic logging method for its intended use have been performed and evaluated. An intensive development of DTS measurement technologies is the matter of nearest future.



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