A NEW ERA IN PRODUCTION LOGGING: DEFINING DOWNHOLE FLOW PROFILES

For decades, production and reservoir engineers have sought to measure fluid flow rates and properties in the wellbore. Early measurement techniques focused on establishing fluid velocity using a single, centrally positioned spinner. This remained the principal fluid-logging tool for production engineers for many years.

The latest production-logging methods provide a much more detailed picture of fluid distributions, temperatures, pressures, and flow rates. In addition, many of the limitations of conventional production-logging tools have been overcome and reliable data can now be gathered in highly deviated and horizontal wells.

In this article, Antoine Elkadi and Murat Zeybek explain how the latest developments in production-logging techniques can help production and reservoir engineers to make better-informed decisions about well and field management.
The quality of the data acquired from traditional production-logging methods depends on the downhole well conditions. These methods are accurate and reliable for vertical wells with high fluid flow rates, but for deviated and horizontal wells with stratified, multiphase flow the data acquired may be misleading. The need for understanding and measuring downhole multiphase fluids with complex flow regimes emerged during the 1990s when the era of drilling deviated and horizontal wells started.

Production logging is the measurement of fluid parameters and flow contributions on a zone-by-zone basis to yield diagnostic data, for example, information indicating the efficiency of perforation. When extensive production-logging campaigns are conducted as part of a reservoir monitoring or surveillance program, operating companies can use the data to assess the individual reservoir compartments and establish their contributions to oil and gas production or water cut. The information gained from production logging can be used to help companies in defining field economics and thus to make the most appropriate decisions for field development and reservoir management.

However, traditional production-logging methods have limitations in many of today’s wells, wellbore conditions, and fluid types. Wellbore conditions have a large effect on the quality of the data obtained. In vertical wells with high fluid flow rates, the data acquired are accurate and reliable. However, multiphase flow conditions exist in many deviated and horizontal wells. In these wells, conventional production-logging tools are often inadequate and may give misleading results (Fig. 1). In the 1990s, the industry began to drill large numbers of deviated and horizontal wells, and so the need to understand and measure fluid flow within complex flow regimes became increasingly important and necessitated the development of new tools and techniques.

A clearer picture

Production logging helps to provide information on flow rate (fluid velocity from spinner rotation), density, temperature, and pressure. In traditional production logging, only the flow rate and density readings were used for quantitative analysis. The temperature and pressure data were used in a qualitative way to compute in situ flow properties and to locate the zones where fluids were flowing into or out of the well (Fig. 2).

Today, production logging provides engineers with a broad range of fluid measurements, including temperature and pressure data. The additional information can be used to improve the quality of interpretations and is particularly useful in highly deviated wells and those with low production rates.

Modern tools and techniques can provide zone-by-zone measurements of flow rates and fluid parameters and so yield information on the type of fluid movement within and near the wellhead. For example, the P2P Production Logging Tool detects mechanical problems, breakthrough, and coning; monitors flow profiles, production, and injection; detects thief zones and channeled cement; and helps to evaluate single- and multilayer well tests.

Identifying unwanted water and/or gas entries becomes more complicated because of the interactions between oil, water, and gas at downhole conditions. Oil and water are immiscible, but gas is miscible with oil, depending on the pressure and temperature, and with water in small quantities. At a specific pressure and temperature, both oil and water can absorb gas until the saturation point is reached. Above this gas-saturation limit, the gas remains as a separate phase. This means that in the wellbore, oil and water both containing dissolved gas and free gas bubbles may coexist and flow toward the wellhead (Fig. 3). The proportions of these fluids in the production stream have a direct influence on the separation process and, ultimately, on the production rates that can be achieved for a particular field or reservoir.

Making sense of multiphase conditions

Interpreting production-logging data and determining downhole flow profiles in single-phase flow conditions are, usually, straightforward processes. Flow profile determination in multiphase conditions is much more complicated. Factors including holdup, slippage velocity, and phase segregation combine to greatly complicate flow behavior. The holdup, for example, is defined as the percentage by volume of the borehole contents (i.e., gas, oil, and water) measured over a cross-sectional area. This cross-sectional area is typically the inner diameter of the production string (casing or tubing). Holdup can be measured at different places throughout the production string and can vary dramatically with borehole deviation and fluid flow rate. Under multiphase conditions, light phases move faster than heavier phases by an amount known as the slippage (slip) velocity. Engineers must therefore determine the downhole holdup when attempting to interpret production logs obtained under multiphase flow conditions.

The main objective for production logging in three-phase-flow wells is usually to establish the flow rates for oil, water, and gas. However, characteristics such as stratification, misting, annular flow, and recirculation can make accurate quantification extremely difficult. Flow rate is a function of holdup and velocity. Engineers who want to evaluate the flow rate of each phase at every depth level along the survey interval must map fluid velocities and holdups inside the wellbore.
Flow structure in deviated and horizontal wells

In vertical wells, oil and water are mixed across the entire wellbore. The velocity profile is smooth, and the water holdup profile varies gradually across the borehole. Averaged measurements across the wellbore, such as those obtained using conventional production-logging tools, are generally adequate to determine the velocity and the holdup in this type of flow regime.

However, once the wellbore deviation exceeds more than a few degrees (say 20°), the centrally positioned sensors of conventional production-logging tools become much less reliable. Phase segregation and small changes in well inclination and flow regimes all influence the flow profile. Logging problems typically occur when conventional tools run in deviated wells encounter topside bubbly flow, heavy phase recirculation, or stratified layers flowing at different speeds.

Flow-loop laboratory experiments that simulate conditions in the wellbore have shown that the flow regimes that develop in highly deviated wells can be extremely complicated (Fig. 4). These flow regimes are controlled by factors including the borehole size and deviation, the fluid holdup, and the velocity, density, and viscosity of each phase. Tests have also shown that even a 1° variation in well deviation can have a dramatic effect on fluid distribution, holdup, and velocity.

Flow-loop studies have also revealed the ineffectiveness of conventional logging tools in multiphase flows once there is strong phase segregation. The measurements made are inadequate for describing complicated flow regimes. In addition, conventional tool sensors are usually spread over a long toolstring, which makes the measurements even more difficult to make.

Mapping fluid velocities

Two of the most significant challenges in developing a new generation of production-logging tools were extending measurement coverage across the diameter of the borehole and making measurements in a shorter depth interval over the wellbore.

One solution was to develop a tool with a range of small sensors that covered the full width of the wellbore and could be placed close together to improve depth resolution. The Flow Scanner® horizontal and deviated well production-logging system has five microspinners and six pairs of electrical and optical holdup probes that are activated downhole once the tool has reached the survey interval. This combination of small sensors ensures almost total wellbore coverage. The microspinners evaluate local fluid velocity, and the electrical and optical probes measure the local water and gas holdups.

In the borehole, the sensors are positioned so that the measurements map the fluid velocities and holdups across the borehole at every depth. This enables engineers to derive a much better estimate of the flow rates for the individual phases within the flow regimes.

Using the Flow Scanner tool in deviated and horizontal wells gives operators a better understanding of production regimes and enables them to define more accurate flow profiles and, consequently, to plan more efficient workovers or production strategies, which will improve the ultimate hydrocarbon recovery.

The Flow Scanner tool was developed using computational fluid-dynamics simulations. Hundreds of flow-loop tests and fluid-dynamics simulations were conducted to optimize the tool’s architecture and the sensor deployment. Unlike conventional systems, the Flow Scanner tool was designed to run eccentric because it is difficult to centralize a tool in horizontal or highly deviated wells. When in the wellbore, the tool opens up into a characteristic triangular configuration (Fig. 5).

Five one-inch-diameter microspinners are mounted on the front arm. Because the tool is designed to rest on the base of the triangle when driven into the hole, the spinners line up along the vertical axis of the wellbore. In this way, the phase velocities along a vertical axis can be mapped at every depth point.

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In wells containing two or more immiscible fluid phases, wellbore deviation causes phases with different densities to separate out with a mixing layer of dispersed bubbles between them. In two-phase systems, the flow structures are characterized by the width of the mixing layer. One of the key factors influencing flow structure is well deviation. The thickness of the mixing layer is fixed for a given borehole diameter and deviation. The composition of the produced fluids determines the position of the mixing layer. As the overall fractional volume of water in the wellbore decreases, the mixing layer moves across the borehole’s diameter.

The effect of borehole deviation on mixing and flow structure is complicated, even in relatively simple two-phase systems such as those containing only water and oil. Three principal types of flow structures can be defined on the basis of well deviation.

Near-vertical wells
In near-vertical wells, the oil and water phases are fully mixed across the entire wellbore cross section. Even for wells with a deviation of less than 20°, the mixing layer is large and the two phases are mixed across the borehole with a smooth velocity profile. However, as soon as the wellbore deviates further, gravity creates a higher concentration of oil in the upper section of the borehole. The profile of the local water holdup begins to vary across the wellbore (Fig. 6A).

Deviated wells
In wells deviated at angles between 20 and 85°, portions of the wellbore cross section have monophasic flow but the overall flow structure is more complex (Fig. 6B). Heavy phases, typically water, segregate at the bottom of the borehole because of gravity, and the mixing layer is located in the upper part of the wellbore and contains dispersed bubbles of oil or gas. In mixed gas-liquid flow, the structure can be more complex. The gas can flow in slugs instead of small bubbles. This flow structure has large velocity gradients and local holdup distributions. At low flow rates, water is frequently recirculating and the water velocity at the bottom of the borehole may be negative.

At high flow rates, differential acceleration of the phases caused by the shear forces between the different fluid phases can lead to Kelvin-Helmholtz instabilities; these almost cause breakdown in stratification. Under these conditions, production-logging sensors that yield average answers are unsuitable for understanding flow structure. Local measurements made across the borehole’s diameter are needed to clarify the velocity and holdup profiles.

Near-horizontal wells
For horizontal and near-horizontal wells (deviations between 85 and 95°), the flow structure is completely stratified, with the water flowing at the bottom and the oil or gas phase at the top with little or no mixing (Fig. 6C). At low flow rates, well deviation has a strong influence on flow behavior. The slightest deviation from 90° causes the monophasic oil and water streams to flow at different velocities.

Figure 6: Three main types of flow structure can occur in a two-phase (water-oil) system.

One of the key factors influencing flow structure is well deviation. This is the angle to vertical at which the well has been drilled.
Boosting production in mature fields

The application of modern production-logging methods has helped some operators to make dramatic production gains. Conventional production-logging tools often have difficulty in defining complicated flow regimes and identifying the areas for the water shutoff needed to maximize oil recovery as fields approach their economic limit.

The Flow Scanner tool was first used in mature reservoirs in the Gulf of Suez, where viscous oils are produced at high water cuts through deviated to horizontal completions. One well with an inclination of 37° was producing with gas lift through six open intervals. The oil production rate was 327 m³/d with a 97% water cut. A conventional production-logging survey could not evaluate the individual interval contributions or identify the sources of water production, so the operators decided to try the Flow Scanner tool, which was deployed on wireline.

The six pairs of electrical and optical probes on the Flow Scanner tool are mounted on the rear arm behind the spinners (Fig. 8). In mixed and segregated flow regimes, the electrical and optical probes measure the localized water and gas holdups, respectively. The electrical probes measure fluid resistance (impedance), which facilitates calculation of the water holdup, while the optical probes use a reflectance method to evaluate the gas holdup.

The spatial location of the different sensors is accurately identified using an integrated, relative-bearing sensor and caliper measurements. The direct measurement of the velocity and fluid-holdup profiles helps the analyst to determine the downhole phase split and reduces the uncertainties associated with multiphase flow interpretation.

The tool arm is motorized with a 1.5-m-long hydraulic module, which is controlled from the surface. At any point in the wellbore, the arm can be made to scan the wellbore slowly during a stationary measurement to pinpoint the position of the fluid interface or interfaces. In addition, the Flow Scanner tool is 5 m long as compared with the 25 m minimum of the best conventional toolstring required to obtain similar measurements, but of lower quality. This shorter logging string saves time and effort at the wellsite.
In comparison with the conventional production-logging survey, the Flow Scanner profile showed that approximately 25% of the oil and 85% of the water were being produced from perforations below X,121 m (Fig. 9). The remainder of the water and some oil were being produced from perforations at X,118 m.

The perforations above X,118 m were producing clean oil, and more than half of the oil was flowing into the top perforation. Conventional production-logging sensors could not detect oil entering the top perforations because the spinner was affected by water recirculation, and the resolution of the Gradiomanometer specific gravity profile tool was too low for it to resolve the oil contributions. As a result, the conventional survey had erroneously attributed 90% of the oil production to the lower perforations.

A workover operation was planned for optimizing production on the basis of the Flow Scanner results. After cross-referencing the log results with the geological information on the location of a sealing shale layer, the field operator set a plug at X,120 m to isolate most of the high-water-cut zones in the bottom of the well. The resulting production (88 m³/d of oil and 403 m³/d of water) represented a nine-fold increase in oil production; payback for the operation was achieved in less than a week.

**Fluid discrimination**

The Flow Scanner tool is engineered specifically to provide real-time holdup and velocity profiles along a vertical axis of the borehole cross section. The holdup sensors used are six GHOST* Gas Holdup Optical Sensor Tool probes and six FloView* electrical probes. The optical probes distinguish between gas and liquid using optical refractive index measurements (Fig. 10). The electrical probes discriminate between water and hydrocarbons using fluid electrical resistance measurements. The velocity sensors are five microspinners. Several years of engineering effort have produced small diameter spinners with velocity thresholds comparable to larger fullbore spinners.

To maintain its orientation in the wellbore, the tool's hydraulically operated arm is extended to a length equal to the diameter of the production tubing so that it serves as a caliper. This arrangement provides the area measurements needed to calculate flow rates. The tool has an outside diameter of 11½ in, and it can be run in holes ranging from 2½- to 9-in diameter using coiled tubing (CT), wireline, or the MaxTRAC* downhole well tractor system (Fig. 11).

The Flow Scanner tool's low-frequency resistivity probes measure fluid electrical resistance to detect water. Water conducts electrical current, whereas oil and gas do not. A threshold is set that enables the tool to distinguish between hydrocarbons and water. Each probe generates a binary signal when oil or gas bubbles in a continuous water phase or droplets of water in a continuous hydrocarbon phase touch its tip.

The water holdup is determined by the amount of time that the tip is conducting current; thus the water holdup profile accurately represents the flow regime in the wellbore. This methodology enables a local water holdup measurement, which is independent of fluid properties, to be determined without calibration. Conventional holdup tools, however, require accurate calibration in oil and water.

The Flow Scanner tool software optimizes and displays the data acquired from the spinners and probes at the wellsite. Two views are constantly updated with real-time acquisition data. One of these views shows the relative fluid velocities measured by the microspinner array, while the other shows the phase distribution across the wellbore section (Fig. 12). In both views, the wellbore is sliced horizontally into the five layers associated with the different combinations of spinner, electrical-probe, and optical-probe measurements.

In the spinner view, five rectangles are plotted with lengths proportional to the rotational velocities of the corresponding spinners. Each rectangle is divided into color-coded sections with widths proportional to the three-phase holdups seen by the electrical and optical probes.

In the cross-sectional view, each layer is color coded to represent the phase with the highest holdup seen by the probes. The holdup values of the two remaining phases are represented by proportionate numbers and bubble sizes. The relative positions of the sensors are also shown, with circles for the spinners and dots for the probes.
Water recirculation revealed

In the Middle East, the Flow Scanner tool has also helped to identify water recirculation along a wellbore completion. This was the first field test for the tool.

The well under investigation was a 7-in cased hole producer with a production rate of 500 m³/day of oil at surface with zero water cut. The wellbore was 47° across the logging interval. The advanced PS Platform® tool had already been run in the well, which meant a direct comparison of its data could be made with data from the Flow Scanner tool. The average value for water holdup above the perforations was approximately 25%.

The fullbore spinner on the PS Platform tool had measured a net, positive (upward) velocity. Because the water holdup was not zero, a conventional interpretation was bound to estimate a net positive water flow rate. When using the conventional toolstring, the zero water cut at surface was the only indication that water must be recirculating downhole. However, the Flow Scanner tool was able to identify and characterize the water recirculation (Fig. 13).

Figure 14 shows the holdup distribution along a vertical axis of the casing; the bottom probe measured water holdup at about 92% and the top one at about 2%. Note that the bottom two spinners measured a net negative fluid velocity, which was mainly that of the water. The water was being dragged up with the oil on the topside of the wellbore only to fall back down on the low side of the casing. The recording made while coming out of hole showed the water column extending to a few hundred meters from surface, but no water was reaching the surface (Fig. 15).

This type of information is a major breakthrough for production logging. Engineers can now visualize and measure heavy-phase recirculation downhole. The image in Figure 15 was taken from a processing application called the Flow Scanner tool Inflow Profiler, which uses predetermined spinner pitches to provide a single-pass interpretation in real time.

The presence of a quasi-stationary water column inside the wellbore was exerting backpressure on the sandface and choking oil production. The operator has conducted a workover operation that involved pulling out the completion, cleaning the water from the wellbore, and recompleting the well as a dual producer.

Challenging conditions

As production-logging technology advances, more accurate and reliable results are being achieved for multiphase flow conditions in horizontal wells. The most significant test of any new technology is in wells where the operational conditions are challenging.

Both of the following examples are from a giant carbonate reservoir in which reservoir thickness varies between 46 and 55 m, porosity varies between 15 and 20%, permeability varies from 50 to 500 mD, and oil gravity varies between 32 to 36°API.

Determining water entry intervals and flow profile

Well 1 was drilled and completed as a slanted 6¼-in openhole horizontal producer. The well was a barefoot completion below the 7-in casing with 4¼-in tubing and a 3½-in tail wellbore extended into the open hole. It was 620 m long and produced oil with 22% water cut at surface. The produced water had a total dissolved solids content reported to be 70,000 ppm, i.e., fresher than the formation water, which suggested the presence of injection water.

The production-logging objectives for this well included determining the water entry interval(s) and the flow profile. The integrated production toolstring used was 28-m long and included a gamma ray sensor at the top and a deployment bar in the middle for two-stage deployment with CT.

The total flow rate was determined in the 4½-in tubing (the deviated section) above the perforated pup joints because of the tail wellbore extension into the openhole section. The agreement between the production-logging tool data and the test trap data was very good (similar amounts of oil with a 26% water cut). The water flow velocity (137 m/min) and the oil-phase flow velocity (142 m/min) were in excellent agreement with the expected slip velocity in this 38° deviated wellbore section.

The oil-phase flow velocity measurement at this deviation proved to be valid, independent of deviation, as long as the oil phase was continuous. Oil and water velocity stations were continued in the openhole section for flow profile determination. To increase confidence in the results, a multiphase holdup pass using pulsed-neutron measurements (Roscoe and Lenn, 1996) was recorded and holdup measurements were made using electrical probes. Both measurements showed very close agreement, see Fig. 15, tracks 2 and 4.
The fluid holdup distribution along the wellbore indicated that there was no oil entry below X,260 m; only water was seen in the wellbore. The first water entry was detected in the toe section, the second in the middle section where the borehole salinity decreased significantly, which indicated the entry of injection water (see track 5, Fig. 16).

In the presence of water and oil, the amount of oil holdup is compensated for to determine the salinity of the water. The sudden increase in oil holdup 60 m above the slanted section of the wellbore gave a clear indication of significant oil entry. In fact, the oil-phase flow velocity measurements detected the entry; this translated, using holdup and caliper data, into 40% of the total oil production. An increase in water flow at stations across the same interval translated into a 60% water entry.

The spinner data also indicated a large increase in flow velocity, which supported both the oil- and the water-phase measurements. This interval was identified as a superpermeable zone that had not previously been identified in logs. Productivity index information was obtained from the measured total flow rate and the pressure drawdown data.

**Quick and accurate production logging**

Well 2 was drilled and completed as a 6 1⁄8-in open hole and was initially producing dry oil. The test trap showed 40% water cut after six years' production. Before logging, the well showed a 51% water cut with an 80/172 choke size. During logging with CT, the well was flowing with an 80/172 choke size and a flowing wellhead gauge pressure of 4,620 kPa. The logging operations aimed to determine the water-entry interval and the flow profile. The compact, integrated Flow Scanner production logging toolstring was used to provide fast rig-up without deployment. The flowing passes were planned and completed within 15 h from rig-up to yield real-time answers.

The job was planned to include one downward and one upward pass, including stations, with a repeat pass if required to achieve the objectives on the basis of the real-time results. Image logs were available during logging and were integrated with the openhole logs. The total flow rate determination was performed above the perforated pup joint to detect any

The downhole flow rate, \( Q \), is estimated at every depth point from the formula:

\[ Q = V \cdot A \]

where \( V \) is the velocity of the phase in question, \( Y \) is its holdup or the fraction that it occupies in a unit volume, and \( A \) is the surface area that is available to the flow.

When using conventional methods, the oil and water velocities were measured during stationary acquisition. The vertical resolutions of the measurements are about 0.5 and 7 m for water and oil respectively (see figures 17 and 18).

Because the oil and water velocities are not measured at the same instant, inconsistencies can be introduced into the computations. In addition, the stationary nature of the measurement has a detrimental effect on the resolution of the velocities calculated; surveying a 200-m interval with 15 m between stations would require about 5 h for each velocity measurement. Therefore, a distance between stations of less than 15 m is usually avoided because of the time constraints. Consequently, the final flow profile will usually have a vertical resolution of only about 15 m using the PS Platform tool.

For making holdup measurements, four or eight probes are deployed circumferentially in the wellbore. In highly deviated and horizontal wells, this distribution is not optimum for full holdup coverage and accurate determination of the fluid interfaces. Tool rotation can lead to a symmetrical probe distribution where two probes are at the same level and therefore measuring the same flow component (Fig. 19).
The future

Efficient integrated production logging improves understanding of well behavior and reservoir characterization under challenging conditions. The Flow Scanner tool offers major improvements over conventional production-logging technology. Although it uses established principles of measurement, the miniaturization of the spinners and the mounting of the sensors across the diameter of the wellbore clearly represent the oil and water velocities respectively.

No fluid contributions were observed from some features that had been described as open or conductive fractures. The image log of the first entry interval showed only a few fractures, yet, it contributed 42% of the water. Across the second entry interval, one fracture was evident; this interval was responsible for 58% of the water entering the well. Some of the imaged conductive fractures located above the water-entry interval were not associated with the detected fluid entry, which suggested that conductivity determination could be directly obtained from dynamic data such as production logging.

Careful planning

Prejob planning and integration of all the available well data and logs to achieve the logging objectives and maximize the reservoir characterization information are essential for efficient logging data acquisition. Recent successes have demonstrated that, by using advanced tools and techniques, integrated production-logging acquisition, with either CT or tractor conveyance, can be designed to successfully achieve challenging production-logging objectives in open holes, including boreholes with highly deviated or horizontal sections.

Production logging can include the identification of superpermeable zones or conductive fractures and the direct assessment of their flow contributions; the description of water salinity variations to define injection water entries along the wellbore; and the evaluation of production pressure losses. The compact, integrated Flow Scanner tool provides fast, efficient rig-up and rig-down; promotes safer operations; and delivers real-time data analysis in support of challenging objectives.

Figure 20: Results of new compact integrated production logging in Well 2.

Figure 21: Well cross section and sensor measurements in real time in Well 2.

Reference