Revitalizing Production Logging

Thousands of high-angle and horizontal wells have been drilled in the last ten years.
As a result, there are many mature fields with complex well production problems.
Today, new technology and better understanding of fluid flow in wellbores have revived production logging methods for all types of wells.
For decades, production logs have been used in new wells to optimize ultimate recovery and to help avoid potential production problems. In older wells, these logs aid in diagnosing declining production and planning remedial work.1

From the outset, production logging (PL) has been used to determine the dynamic patterns of flow rates of water, oil and gas under stable producing or injecting conditions by answering the following questions: How much of the well is flowing? Which zones are producing oil, water and gas? How much of each type of fluid is flowing from each zone?

Ideally, PL techniques should identify each fluid, measure the volume fraction of each fluid in the pipe—called the holdup—and its velocity, and from these compute flow rates.2 Traditional PL measurements use turbine flowmeters called spinners for velocity, gradiomanometers for density, capacitance for holdup, manometers for pressure and thermometers for temperature. Of these five measurements, only velocity and density tend to be used in traditional quantitative PL analysis.

The reliability of the data generated by traditional PL logging depends almost exclusively on the type of well being logged. In vertical wells with high flow rates—usually from 200 to 5000 B/D [30 to 800 m³/d], depending on the tool used and the pipe diameter—these PL measurements and their analysis usually produce reliable results. However, in some wells, phenomena such as flow behind casing or interzone flow make traditional PL difficult.

The upsurge in deviated and horizontal wells creates boreholes with very different fluid flow characteristics from vertical wells, adding further complexity to multiphase flow and radically changing the physics and technology of fluid-flow measurement (above). In gas-and-liquid or oil-and-water flow, the lighter phase moves rapidly along the high side of the borehole, establishing a circulating current that often causes a backflow along the lower side (see “Fluid Flow Fundamentals,” page 61).

Depending on the borehole deviation, the velocity and holdup of the different phases can change dramatically for any given flow rate. In these circumstances, traditional PL measurements may become unreliable.3 This article looks at how new techniques are helping to shed light on flow in complex vertical wells, and to deliver PL measurements in deviated and horizontal wells.

When to Run Production Logs

Generally, PL has two important applications: measuring well performance with respect to reservoir dynamics and analyzing mechanical problems in the borehole. Although decisions to run production logs usually depend on specific reservoir economics, there are general guidelines.

First, PL may be used in new wells to evaluate initial production and verify the integrity of the completion—for example, indicating where there is flow behind casing. When initial performance does not meet expectations, information from PL may often point to remedial work to optimize production and suggest different completion techniques for future wells.

A special use of PL in horizontal, high-rate wells is to verify friction-induced production loss in long drainholes. This friction loss sometimes negates any extra productivity expected from the long drainhole, and a better choice would be to drill multiple, shorter lateral sections in a stacked or fan-shaped pattern.4

Second, PL should be considered for any well that shows sudden decreases in production or increases in gas/oil ratio (GOR) or water cut.

Third, just as a yearly checkup by a physician is prudent, PL may be used periodically to detect problems such as water or gas coning, or fingering before extensive production loss occurs. This is particularly important for dump-flood wells, where PL is the only monitoring method.5

Fourth, injection wells may be initially analyzed and then monitored with PL. Knowledge of where injected fluids are going is critical for avoiding undesired flooding that leads to serious problems such as casing-annulus crossflow, the creation of unswept and trapped hydrocarbons, and water-wet damaged formations.
The ability to carry out downhole PL measurements in a stabilized well under dynamic conditions is the key to successful production management. The resulting downhole flow-rate determination may be compared with stabilized surface flow rates. This quantitative comparison between downhole and surface flow rates allows detection of any surface-to-downhole discrepancies caused by such factors as tubing leaks, thief zones, unwanted fluid entries or other hydraulic malfunctions.

Production Logging in Vertical Wells

Increasingly, operators incorporate PL into their reservoir monitoring programs. Today, this often includes cased-hole saturation logging techniques—such as thermal-neutron decay time or carbon-oxygen measurements—run in combination with traditional PL tools to provide an enhanced understanding of reservoir dynamics. The RST Reservoir Saturation Tool can be used to make a snapshot of reservoir saturation. Repeating these measurements over time helps monitor changes in reservoir saturation. But the dynamic description of flow conditions obtained from production log profiles is absolutely necessary to unravel complex commingled production in a many wells.

For example, to gain a clear picture of production dynamics in a declining reservoir, the CPLT Combinalble Production Logging Tool log and the RST technique were used in combination in a reservoir located in the Pearl River Mouth basin in the South China Sea. The reservoir, a sand-shale sequence, was producing from four commingled sandstone formations, and the operator needed to understand current reservoir production on a layer-by-layer basis. The CPLT-RST reservoir monitoring suite was deployed in a well located at the top of the reservoir (previous page). Openhole well evaluations, with the latest hydrocarbon volume from RST C/O monitoring, showed the changes in reservoir saturations.

The lowest zone had been completely depleted, as had about half of the next zone. A cased-hole versus openhole gamma ray comparison revealed evidence of substantial scale buildup in the lowest perforated zones. This indicated that large volumes of water had been produced from the lower zones, and scale could potentially plug perforations.

The production logs provided the key to understanding what was happening in the well. The flowmeter and gradiomanometer profiles showed that there was only a little fluid production, mostly water, coming from the lowest perforations. About 60% of the total water production came from the second lowest set of perforations, and most of that from just 2 m [6.5 ft] of the upper section of perforations.

Surprisingly, the RST monitor log indicated that water production was coming from a fully oil-bearing part of the formation. It was suspected that the water was coming up from the bottom part of the zone, now completely depleted of hydrocarbons. Logs from other wells, downdip in the reservoir, confirmed this conclusion. Reducing the drawdown pressures may allow production of the bypassed hydrocarbons, still contained in this zone, to continue.

In the well’s second highest perforated zone, the RST monitor logs showed a significant oil-water contact (OWC). The lowest half of the zone was fully depleted, whereas the upper half was untouched by production. Unexpectedly, production log profiles indicated greater hydrocarbon production than water, perhaps because scale had plugged the lower perforations in the watered-out part of the zone. The upper perforations in this zone did not appear to be plugged by scale, yet the production profiles showed minimal contribution over the entire interval. This result confirmed the diagnosis from RST monitoring logs that the upper formation layer had been swept of all movable hydrocarbons.

Another example, this time in a vertical well with a thief zone and borehole water entry, occurred in India’s offshore Bombay High field, operated by Indian Oil and Natural Gas Commission (ONGC). The reservoir was under waterflood, and the operator needed to identify zones of water entry and to determine whether flow was occurring behind the casing. It was also suspected that injection water had broken through and was being produced from one of five sets of perforations.

A WFL Water Flow Log tool was combined with the PLT Production Logging Tool log to distinguish between flow inside and outside the casing (see “Fluid-Flow Logging Using Time-of-Flight,” page 50). The downhole flow rates were complex. The top of the lowest set of perforations, Zone 5, produced only small quantities of water. There was a large increase in water flow coming from the second lowest set of perforations. A modest amount of oil, 400 BOPD [63 m3/d], was also produced from this zone. The middle set of perforations, Zone 3, also produced 1000 BWPD [160 m3/d] with only a small amount of oil. The second highest set of perforations showed no fluid production (next page).

5. In dump-flood wells, water is produced from an aquifer and injected into a producing formation in the same well.

An essential input for RST-A C/O monitoring logging is the oil holdup in the borehole. The PL gradiomanometer provides this measurement.
With the top set of perforations—Zone 1—the picture changed dramatically. Here, more than half of the production from the four zones below disappeared into the formation. Zone 1 was acting as a major thief zone, consuming 120 BOPD [19 m³/d] and about 2200 BWPD [350 m³/d] from the well. This unusual crossflow, verified by WFL results, indicates a pressure differential between the two formation layers, which was not present when the well was initially put on production. The WFL survey also indicated that there was no channeling behind the casing.

Armed with this knowledge, the operator had two choices for remediation—squeeze the perforations in the lowest zones (3 to 5) to prevent water production, or isolate Zones 1 and 2 using a dual-completion scheme, putting the long string on gas lift, and allowing continued production of 400 BOPD [64 m³/d] from Zone 4.

Nonvertical Production Logging

Once a well substantially deviates from vertical and multiphase flow becomes complex, spinner tools often indicate only reverse flow—especially when the spinner is not centralized in the borehole, but lying near the bottom where the reverse flow is found (next page, right). Capacitance tools may also measure the lower, denser phase of the fluid giving misleading holdup data. As the well's angle increases to horizontal, flow becomes entirely stratified, and the averaged mixture velocity from a flowmeter spinner alone is meaningless.

Other phenomena affect PL measurements in deviated and horizontal wells. For example, stagnant fluids may confuse sensors; fractures and faults may allow crossflow; and failed external packers may introduce variable flow regimes (see page 45).

Horizontal and many deviated wells are often completed either open hole, with uncemented slotted liners or with prepacked screens. Such completions introduce other special fluid-flow and production problems that usually are not encountered in vertical, cased wells—such as flow restrictions due to the logging tool in the pipe forcing fluids to channel through the liner-formation annulus. Furthermore, a
Distinguishing between water flow inside and outside casing. Time-of-flight gamma ray time-decay distributions indicated whether the flow is inside or outside the casing. The lower graph shows the response when water is flowing inside the casing. The blue shaded area reflects the final time-decay response to flowing water after the background and standing water signals have been removed. The blue area had a sharply peaked response, which indicated that the slug of activated water flow occurred in a smooth cross-sectional pipe area without dispersion. The top graph indicates the magnitude and shape of the time-decay response when flow is outside casing. Here the time distribution was much broader, reflecting slug dispersion as it flowed around the outside of casing. Lower total counting rates are due to gamma ray attenuation in the casing.

Special problem occurs near the uphill end of a slotted liner. Here, annular fluids are forced out of the annulus back into the liner or casing, resulting in significant turbulence that tends to mix the fluids. This turbulence can encourage backflow to develop on the low side of the hole, which can seriously affect flowmeter readings.

In horizontal wells completed with conventional cemented liners, flowmeter spinner profiles look more like their vertical counterparts, often showing smooth, distinct evenly-separated profiles when recorded at different speeds. However, cementing in horizontal wells is usually not as successful as in vertical wells because the liner is decentralized within the borehole, often leading to cement voids and channels with accompanying annular production.

Other problems in horizontal completions include acceleration of fluids due to gravity when undulations in the well profile are sufficiently large. If peaks of the flowmeter measurements are taken as representative of the full mixture velocity, the trend is an increase in velocity where the well turns downward and a decrease as the flow reaches the trough of the undulation. Backflow always appears to occur in inverted, undulating wells where the heavy phase falls down the low side of the drainhole. In many cases, the heavy phase (usually water) simply circulates in the sump and is not produced.

Delivering Data from Deviated Wells

Success in isolating crossflow problems in the offshore Bombay well convinced the operator to try a combined WFL-PLT approach in a cased-hole, deviated well that was producing oil, water and gas. The operator was unsure of the exact location of the water entry zones and whether these could be sealed off using cement squeezes to reduce water cut.

Again, channeling behind casing was suspected. This time, the WFL measurements showed this, and confirmed the PLT measurements in a difficult environment. The spinner tool data below X050 indicated downflow, the temperature gradient suggested possible upward fluid movement and the gradiorientor tool showed a single-phase fluid below X050—a very confusing picture.

The spinner measurement was presumed unreliable in this zone, as it had insufficient resolution to measure low apparent flow. The thermometer was affected by fluid movement inside and outside the casing, but could not differentiate between the two flow regions. The WFL data helped resolve the dilemma, by distinguishing between flows inside and outside the casing (above left). In this case, water was flowing outside...
Several years ago, the WFL Water Flow Log technique was introduced using the TDT-P Thermal Decay Time tool to provide water-velocity data, first in vertical wells, then later in deviated and horizontal wells. Today, the RST Reservoir Saturation Tool log provides water-velocity information with more precision. A burst of fast neutrons from the RST tool activates oxygen atoms in a small region surrounding the neutron source in the tool. This includes any oxygen in the water flowing in the pipe. Oil does not contain oxygen and therefore is not affected. Activated oxygen atoms, in a process like fluorescence, give off radiation, in the form of gamma rays, radiating for a short time after the neutron burst.

Moving water in the pipe will carry a cloud of activated oxygen with it past the detectors in the tool (above right). The time between the neutron burst and the detection of the activated water cloud will be a time-of-flight for the water flow in the pipe, and is used to compute water velocity. The half-life of the oxygen activation is only seven seconds, so after a few minutes, the activation radiation has subsided to an undetectable level, making the measurement environmentally safe.

There are two detectors in the RST tool. The tool can use a variable neutron burst width from 0.1 to 3 sec with delays from 3.5 to 20 sec to measure water-flow rates from as low as 6 ft/min [1.8 m/min] to as high as 500 ft/min [152 m/min]. The RST tool may be inverted to measure downward water flow. An additional gamma ray (GR) detector may be incorporated in the logging tool string to measure higher velocities.

The RST-WFL technique may be used to measure other parameters. The total activation count rate is proportional to the volume of water activated by the neutron burst, and therefore is a measure of the water holdup in the pipe. The time profile, or shape, of the activation count rate distribution carries information about whether the activated water is flowing near the tool in the borehole or behind the casing pipe in the annulus.
For horizontal wells, fluid flows are stratified, with the light phase moving rapidly in the upflow sections of the well along the high side of the borehole. Slight changes in borehole deviation cause large changes in fluid holdup and the velocities of different phases, making it necessary to know all fluid velocities. Spinners are usually not applicable in stratified flow, and radioactive tracers are useful only for water-velocity measurements, because there are no oil-miscible forms available. Radioactive tracers also have strict procurement and safety issues.

The PVL Phase Velocity log also uses a time-of-flight method to measure both oil and water velocities. This technique uses a chemical marker that is injected into either the oil or water stream. The time the marker takes to reach the detector is a measure of fluid velocity (previous page, bottom). The chemical marker contains a high concentration of the element gadolinium, which has a large thermal neutron absorption cross section. The RST tool senses the large increase in the borehole absorption cross section caused by the passage of the gadolinium slug (above).

A high concentration of gadolinium chloride [GdCl₃] in water is used as a water-miscible marker. It has the high density and low viscosity necessary for the water-phase measurements. For the oil-phase measurements, a new, gadolinium-rich compound, with low density and viscosity is used. These markers are safe to handle, even in concentrated form, and pose no environmental threat when injected into borehole fluids.

Flow-loop experiments at Schlumberger Cambridge Research, Cambridge, England have validated the PVL measurements under a large variety of flow conditions. Both single-phase oil and water measurements show excellent agreement between PVL-measured and actual flow rates (above). Two-phase measurements, using oil and water or gas and water, demonstrate the ability to measure separately each phase in a segregated flow (right).

2. Albertin et al, reference 6, main text.

Two-phase velocity measurements in the Schlumberger Cambridge Research flow loop. Oil and water velocity measurements made using the PVL technique in a laboratory flow loop with two-phase flow where the water flow rate was maintained constant at 1500 BWPD. The loop was tilted from 85 to 92 degrees and the water and oil velocities measured for oil flow rates ranging from 750 to 3800 BOPD. The results show that small deviations from horizontal can cause large changes in the measured fluid velocities.
the casing below X050 m causing the temperature to change faster than the local geothermal gradient. Above X050 m, the WFL data revealed flow inside the casing, in good agreement with the production logging interpretation (right).

The WFL interpretation helped pinpoint the three-phase production to Zones 2 and 3. Only gas and oil enter the well from Zone 1. The WFL data show that water, from below Zone 5, flowed behind the casing. With a clear understanding of the production problems in the well, the operator could choose between two remedial treatments—eliminating all water production by closing Zones 2 and 3, simultaneously cutting potential oil production by a third; or simply decreasing water cut by repairing the cement below X050 m.

The next field example shows how a new PL holdup and velocity imaging tool helped determine the correct remedial action for a well on the North Slope, Alaska, USA operated by ARCO Alaska Inc. and BP Exploration (next page, left). The 49° deviated well, was flowing at 1141 BOPD [181 m³/d] with 82% water cut at surface and a GOR of 2583 ft³/bbl. Four zones were originally perforated, and traditional PL interpretation based on density, velocity and temperature indicated mixed water and oil production in the lower three zones, and gas in the top two. For example, in the lowest perforated zone, the gradiomanometer showed a reduction in fluid density, usually interpreted as first hydrocarbon entry. Based on traditional PL measurements and interpretation, only this lowest zone would be produced, and all upper zones would have been plugged.

A completely different picture emerged using the recently introduced FloView imaging tool (see, “Advantages of Holdup and Bubble Imaging in Production Logging,” page 54). The FloView water holdup curve remained at 100% in the lower zone. The density drop measured by the traditional gradiomanometer probably occurred when the tool moved from a dense sump fluid lying below the lowest perforated zone into lighter water produced from the first set of perforations. Next, the FloView holdup detected a small hydrocarbon entry in Zone 2, and a large entry in Zone 3, as seen in the FloView holdup map.


Water flow logs at different depths in a deviated well. Track 1 (left) shows a well sketch and perforations at each zone. Track 2 shows WFL velocity results. The next three tracks show PL density, temperature and pressure measurements. Results of flow model analysis are shown in Track 6 (right). The reconstruction of PL measurements (dashed red) based on the flow model analysis is shown along with the original (solid black) PL measurements in Track 5. Three detectors were used by the WFL to cover a wide range of flows. Water velocities inside the casing, derived from the near detector are shown as green circular tadpoles, while the far detector readings are shown in blue and the gamma ray readings in red. The triangular-shaped tadpoles represent readings for flow outside the casing. In this display, the 45° angle of the tadpole tails show an upflow in the well. Downward flow would be indicated by tails pointing 45° downward.
In addition, the FloView bubble (or hydrocarbon) velocity map pinpointed the first significant hydrocarbon entry midway up Zone 3. The caliper readings, shown as a casing cross-section profile, supported the idea that the gradiomanometer interpretation was adversely influenced by changes in casing diameter between Zones 1 and 3. A restriction in the casing at X900 ft caused an increase in both spinner and FloView velocity measurements.

Just above X900 ft, between Zones 3 and 4, there was a reduction in average FloView bubble velocity. The FloView images showed a narrow band of hydrocarbon in this section of the well—low water holdup and higher bubble velocity throughout the top section of the casing. This zone appeared to have water backflow shown by comparing an overlay of two passes of the FloView velocity, one going up the well and a second traveling downhole. A large separation between the up and down passes was seen in the region experiencing the water backflow. The upgoing FloView pass read higher hydrocarbon velocity than the downgoing pass. This occurred because water was flowing backwards down the pipe, carrying hydrocarbon bubbles down with it against the upward motion of the tool. This abnormal separation in FloView velocities is an easily recognized flag to spot reverse flow in the well.

Farther up the well, the opposite occurred. Starting at Zone 4, the upgoing FloView pass had a lower hydrocarbon velocity than the downgoing pass. This occurs because hydrocarbon bubbles, carried by the upward flowing water, were moving along with the upward moving tool—a sign of significant hydrocarbon entry in Zone 4.

The downhole flow rates and profiles computed from the imaging measurements were significantly different from those determined using traditional PL measurements alone. Flow rates calculated using data from this new technique were within 8% of actual production rates (above). Based on these results, the recommendation to the operator was to plug off all the zones except Zone 3, the only significant oil producer.

The overlay techniques shown in this example can be used as a qualitative method of identifying zones of hydrocarbon entry and water backflow.
The 11\(\frac{1}{16}\)–in. FloView production logging tool makes four independent measurements of borehole fluids, distributed in different quadrants of the pipe cross section (right).

The self-centralized device uses matchstick-sized, electrical probes to measure the resistivity of the wellbore fluid—high for hydrocarbons and low for water. The probes are located inside of each of the tool's four centralizer blades to protect them from damage, and their azimuthal position within the pipe cross section is measured.

The FloView imager may be run in up to 9\(\frac{3}{8}\)-in. casing. Each probe is sensitive to the local resistivity of the fluid within the pipe and generates a binary output when their sharp leading edges impinge on droplets of oil or gas in a water-continuous phase, or conversely, water in an oil-continuous phase (next page, left). Assuming the fluids are distinct and not in an emulsion form, and that the bubble size is larger than the tip of the probe (less than 1 mm), both water holdup and bubble count measurements may be obtained from the binary output of the probe.¹

Water holdup is computed from the fraction of the time that the probe is conducting, and bubble count comes from the average frequency of the output. In a water-continuous phase, an increasing bubble count means an increasing hydrocarbon velocity, and vice versa in an oil-continuous phase. In biphasic fluid flow, the oil or gas holdup may be obtained from a closure relationship with the water holdup—the closure relation simply states that the sum of the holdups of all the phases equals unity. The probes cannot discriminate oil from gas.

Even in three-phase fluid flow, this device still yields an accurate water holdup measurement. Averaged local outputs for holdup and bubble count are determined for each of the four individual probes. The outputs from each of these probes are combined to map local stratified holdup.

In a typical two-phase environment, the FloView tool has many advantages over the gradiomanometer (next page, right). Jetting of producing fluid in front of perforated zones or changes in pipe diameter because of scale or restrictions have a venturi pressure effect on gradiomanometer response. The gradiomanometer does not measure density directly, but measures the gravitation pressure gradient with differential sensors over a known vertical height difference. For this reason, gradiomanometer measurements are more difficult in highly deviated wells and are impossible in horizontal wells because the vertical separation between sensor measure points is reduced and the measurement loses resolution. Finally, if the flow velocity is sufficiently high, friction will affect the gradiomanometer response.

¹ During most field tests, bubble sizes vary between 1 and 5 mm, within the requirements of the probes. Only at high flow rates (in excess of 2 m/sec [6.5 ft/sec]) are smaller bubble sizes experienced that might affect the holdup and bubble-count measurements.
Principle of local probe measurement. Oil and gas do not conduct electric current, but water does. Water holdup is determined by the fraction of time the probe tip is conducting. Bubble count is determined by counting the nonconducting cycles.

FloView tool and gradiomanometer comparison in two-phase flow. At the bottom of the well (middle), there is frequently some mud and dense stagnant water. The gradiomanometer (right) responds to density change, and will detect the density decrease above the stagnant fluid, which in many cases might be mistaken for oil entry. FloView probes do not respond to the water change since both water and stagnant water are conductive. Therefore, the holdup (left) remains at 100% and the bubble count stays at zero. The next zone is producing water, typically opposite perforations. The gradiomanometer detects another density change, and as before, this change may be misinterpreted as an oil entry, because the produced water is invariably less dense than the stagnant water. Once again, FloView probes do not respond to this water change since both waters are conductive. At the first oil entry in the next zone, the outputs of the FloView probes will indicate less than 100% water holdup, and the bubble count will start to increase. The gradiomanometer density will also record the change, if enough oil enters, and the oil density is sufficiently different from the produced water. As the tool passes across additional oil entries, FloView water holdup will continue to decrease and the bubble count will increase. The gradiomanometer will also register these oil entries with a decreasing density, if the oil entries change the mixture density significantly.
Horizontal Wells: The Flagship Project

During 1994, British Petroleum Exploration Operating Co. Ltd. and Schlumberger Oilfield Services established a joint initiative—"The Flagship Project"—to develop new techniques for the diagnosis and treatment of high-angle and horizontal well production problems.

The diagnosis part of this project involved development of new PL tools. First, a novel tool string incorporating sensors targeted at the stratified flow regimes encountered in horizontal and near-horizontal wells was developed—combining the CPLT tool, an extra gamma ray detector, the RST tool, FloView Plus tool, fluid marker injector and a total flow rate spinner tool (above). This equipment is now being used in the North Sea and the Middle East to make quantitative flow-rate measurements of oil and water in cemented and perforated liners, with a long-term goal of being able to measure three-phase flow in uncemented liners.

The first application of this tool string was to resolve flow profiles and monitor movement of OWCs in the Sherwood sandstone reservoir, in the Wytch Farm field that straddles the coastline of southern England. Using extended-reach drilling technology, at least ten onshore wells were drilled with stepouts of up to 8000 m [26,248 ft] and having reservoir sections of up to 2700 m [8858 ft]. The wells have electrically submersible pumps (ESPs) and produce up to 20,000 BOPD [3178 m³/d]. To manage the field, BP employs production logging on selected wells to assess flow profiles with respect to reservoir zones and to monitor the movement of OWCs. This information is used to determine future well trajectories, optimize standoff from the OWC and target future well intervention needs, such as to shut off water and add secondary perforations.

Holdup image from Wytch Farm 1F-18SP well. Multiple positions of the imaging probes provide a detailed local holdup image. From this image, the local holdup profile is combined with the different phase velocities to determine multiphase fluid-flow rates.

Three Wytch Farm wells were chosen to evaluate the new Flagship tool string—two with water cut and one a dry-oil producer. The first water-cut well 1F-18SP was drilled to a 4450 m [14,600 ft] total depth, with a horizontal displacement of nearly 3800 m [12,468 ft]. Once the main drainhole was drilled through the productive section, the well trajectory was dropped to penetrate the OWC. This permits future logging of the OWC as it moves. The reservoir was perforated 33 m [106 ft] above the initial OWC, giving an initial estimated productivity index (PI) of 100 B/D/psi.

Production started at 15,000 B/D [2384 m³/d] dry oil, declining after three years to a rate of 13,000 B/D [2066 m³/d] fluid with a 9 to 14% water cut at the time of logging. This well was selected to test the new tool string because it had the highest water cut in the field, penetrated the OWC and presented the best opportunity for coiled tubing intervention.

Despite using a revolutionary tool string for this trial, the logging objectives were typical of any PL job: To determine the source of water production, identify the oil and water profile in the well and assess each zone’s contribution, and determine any movement of the OWC in the reservoir.

Analysis of the PL data revealed that the well was producing fluid along the entire length of its perforated section. Water production was occurring only in the lowest perforations—in the toe of the well—possibly due to coning in a zone of high vertical permeability, rather than a general movement of the OWC.

The RST-Sigma saturation monitor logs showed that the OWC had moved up only 10.8 m [35 ft] from its original position. The independent WFL velocity and the PVL water-velocity measurements both showed good agreement with the PL results. In addition, oil-velocity measurements were obtained from the PVL tool.

Local probes on the FloView tool provided holdup distribution images of the fluids, confirming that the flow was stratified (previous page, bottom). In addition, RST-C/O ratio and borehole salinity from the RST-Sigma logs were used for holdup analysis (see “Multiphase Holdup Measurements,” right).12 All three methods—FloView Images, C/O ratio, and borehole salinity—provided similar results, confirming trends or conclusions about holdup analysis. Flow profiles were computed from the velocity and holdup measurements for both oil and water phases.

### Multiphase Holdup Measurements

Multiphase holdup measurements are made with the basic RST C/O measurement, which is usually used to determine the volume of oil in the formation. The carbon and oxygen signals are generated by fast neutron inelastic scattering, which leaves these elements in high-energy excited states that decay immediately by gamma ray emission.

Most carbon-oxygen excitations take place within 15 to 23 cm [6 to 9 in.] of the tool. This means all C/O measurements are sensitive to the local elemental concentrations, and therefore to the relative amount of oil and water holdup in the borehole as well as the saturations in the formation (above).

The RST-A tool has two detectors with one more and one less sensitive to the borehole environment by virtue of their spacing from the source. Gamma ray spectra from both detectors lead to relative elemental carbon and oxygen yields, which are used to solve simultaneously for the volume of formation oil and the borehole oil holdup.1

The RST C/O crossplot response and RST-A inelastic near-to-far count rate ratios are used together to determine multiphase fluid holdup. The inelastic spectra give carbon-oxygen ratios and detector count rates. The crossplot near and far C/O ratio responses are determined primarily by oil holdup in the borehole (lower right plot) and oil volume in the formation. The near-to-far inelastic count rate ratio (upper right plot) primarily depends on the overall borehole density which is related to the borehole gas holdup, \( Y_G \).

The data acquisition capability of the tool string allows most critical parameters to be determined by alternative independent methods—for example, C/O and imaging holdup data, or WFL and PVL velocity data supported by spinner measurements—instilling greater confidence in the results.

The new tool string clearly identified all the water entry points in the well, confirmed that the downhole flow was stratified, and proved that water and oil flow rates could be accurately determined using the new phase velocity and C/O-based holdup measurements. The upper perforations were producing oil. Oil flow rates derived from the PVL velocity and C/O holdup, within 500 B/D [80 m³/d], were 12,500 B/D [1986 m³/d]. The water-flow rates derived from the PVL and WFL measurements, within 500 B/D, were 3500 B/D [556 m³/d].

In the second water-cut well to be logged with the PL Flagship tool string, water entry was found to be not from the toe as before, but from a nonsealing intersecting fault. The logs showed that water was being drawn up through the fault from the OWC.

In the third well—a dry-oil producer—the PVL oil-velocity measurements were tested against a fullbore spinner flowmeter in the horizontal drainhole completed with sand screens. The PVL data matched the spinner velocity, which functioned effectively in monophasic production.

**Tying It All Together—Interpretation**

Traditional PL interpretation for vertical wells primarily uses density from the gradiomanometer to compute oil and water holdup, and the averaged measured flowmeter velocity from the spinner to compute fluid-flow rates using the slip velocity computed from a fluid model. Slip velocity is the difference between the two-phase average velocities. For discussion of traditional production log interpretation: Hill AD, reference 2.

Pressure, temperature and other data are largely ignored by conventional PL analysis. However, such a limited approach is inadequate for most wells. By using all available production logging data, more complete answers may be delivered with greater confidence. The BorFlo production logging analyzer is being introduced to do this (above right). This single interpretation package uses physical models based on fluid dynamics in deviated and horizontal boreholes, relating the physics of fluid flow to the parameters measured by the PL tools (see “Interpreting Multiphase Flow Measurements in Horizontal Wells,” next page). With this interactive PL interpretation tool, measurements may be stacked, tool responses calibrated and flow-rate solutions determined.

Multiple measurement of production parameters—such as fluid velocities from spinners, WFL and PVL logging runs, as well as holdup measurements from imaging tools and RST logs—enable delivery of optimized solutions to the fluid-flow dynamics. Knowledge of sensor responses allows the optimization to be based on the confidence levels of each logging measurement.

This forward-modeling program tests the results of different flow conditions, based on many iterations, to determine the most likely downhole fluid-flow regime that is consistent with all the borehole geometries, wellbore environment, and observed production logging and surface measurements.

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13. Pressure, temperature and other data are largely ignored by conventional PL analysis. However, such a limited approach is inadequate for most wells. By using all available production logging data, more complete answers may be delivered with greater confidence. The BorFlo production logging analyzer is being introduced to do this (above right). This single interpretation package uses physical models based on fluid dynamics in deviated and horizontal boreholes, relating the physics of fluid flow to the parameters measured by the PL tools (see “Interpreting Multiphase Flow Measurements in Horizontal Wells,” next page). With this interactive PL interpretation tool, measurements may be stacked, tool responses calibrated and flow-rate solutions determined.

14. For example, the Duckler analytical model is used to determine parameters of the gas/liquid flow regime, and the volumetric model developed by Choquette and Pierse separates the oil/water regime. For more on the development and use of the constrained solver PL interpretation models such as PLGLOB: Torre J, Roy MM, Suryanarayana G and Crossaid P: "Go with the Flow," Middle East Well Evaluation Review 13 (1992): 26-37.
A new fluid dynamics-based interpretation model called the Stratflo model has been developed to compute oil-water flow rates from logging measurements in high-angle and horizontal wells. The model depends on basic flow equations, which, in turn, depend on dynamic parameters such as fluid velocities and holdup, and static parameters such as well diameter, borehole deviation, and fluid densities and viscosities. Frictional terms at the casing wall are based on monophasic results (right). At the phase interface a simple flat interface frictional model is assumed. A correlation for the frictional factor between the two phases has been developed from flow-loop measurements.

The model is based on the principle that the pressure variation \( \Delta P \) along the axis of the well in each phase is equal. In steady state, the pressure variation in each phase has a hydrostatic component, which depends on density and the borehole deviation (the difference in height of the vertical positions), and a frictional component, which can be divided into two parts: the shear stress on the wall for oil \( T_{\text{ow}} \) and water \( T_{\text{ww}} \), and the shear stress on the fluid interface \( T_{\text{i}} \).

The steady-state model simply sets the pressure in the oil \( \Delta P_{\text{o}} \) equal to the pressure drop in the water \( \Delta P_{\text{w}} \) by defining a function

\[
F(V_{\text{w}}, V_{\text{o}}, Y_{\text{w}}) = 0.
\]

This function is a nonlinear algebraic equation and a function of three independent variables.

To use the model, readily-measured parameters such as local holdup and velocity measurements may be used for two of the necessary input dynamic parameters. With the mass conservation equations, which relate flow rates, velocities and water holdup, the model can be solved for other combinations of inputs, depending on available data. Outputs are computed from the flow model and mass-conservation equations using a root-finding technique.

The flow model gives good results up to about 6000 B/D [953 m³/d] for each phase—the limit where the simple flat interface starts to degenerate as the mixing layer grows. The model accurately accounts for the variation in holdup at different borehole angles and flow rates (right).

\[\text{Interpreting Multiphase Flow Measurements in Horizontal Wells}\]


\[\text{Measured and predicted holdup variation. Holdup was measured at different deviations and flow rates in the Schlumberger Cambridge Research flow loop and compared with results predicted by the stratified flow model StratFlo. The results show the rapid variation in holdup with borehole deviation at low flow rates (red curve), as well as the reduced holdup sensitivity at a high flow rate (yellow curve). The results are shown for a water cut of 50%}\]
The Outlook
The ongoing development effort in understanding three-phase flow is delivering results—including detailed gas holdup and velocity measurements—that are reshaping PL services. However, there is still an important flow domain not adequately covered by today’s technology—environments where there is low water holdup and significant drainhole deviation. Work is under way at SCR to understand the complex fluid dynamics, flow instabilities and phase mixing in all regions. This experimentation together with hydrodynamic modeling will lead to better future understanding and management of flow in the borehole (right).

Improved instrumentation and tool technology are also promising faster, more efficient and lower-cost services—some using slickline. Other applications will see permanent downhole sensors used for production monitoring. These devices are rapidly becoming more sophisticated, measuring properties other than temperature and pressure—such as hydrocarbons and phase mixing.

The outlook for production logging is certainly brighter now that it has been at any time during the last decade. Operators can look forward not only to a better understanding of their reservoirs, but also to use of this knowledge for more effectively managing their assets.

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