Oil and Water Flow Rate Logging in Horizontal Wells Using Chemical Markers and a Pulsed-Neutron Tool.

By Bradley A. Rascuc, Schlumberger-Doll Research & Chris Lenn, Schlumberger Oilfield Assistance Ltd., USA

Abstract

A new approach to obtaining oil and water flow rates in producing horizontal wells has been developed using a pulsed-neutron tool. This approach uses separate measurements of oil and water velocities in combination with separate holdup measurements to obtain the flow rates.

The velocity measurement uses both water-soluble and oil-soluble chemical markers, each of which is insoluble in the other fluid phase for the measurement. The markers are injected into the borehole by a logging tool at one location and detected by a pulsed-neutron tool at a second location. The transit time between injection and detection of the marker gives a measurement of the fluid velocity. Since the markers are soluble only in one phase, the velocity of each phase can be measured separately. This measurement has been made under both laboratory and field conditions to measure velocities from 10 to 500 ft/min at horizontal and several degrees deviation from horizontal. The results of these tests show good linearity and repeatability of the measurement.

The holdup measurement is performed using the inelastic data from a pulsed-neutron tool. With these data, it is possible to quantitatively obtain the holdup of all three phases by combining information from the inelastic near/far ratio with the near and far carbon/oxygen ratio. This approach to the holdup measurement has been demonstrated using a combination of laboratory data, Monte Carlo modeling, and field data. The results of this study have demonstrated that the RMS accuracy of this measurement is about 6% on each of the three phases.

Introduction

As horizontal wells have become more prevalent, the ability to reliably evaluate the production performance of these wells has become increasingly important. Existing production logging techniques, such as spinners, that have been successfully used in vertical wells can not always be applied to horizontal wells with full confidence due to the segregated flow in the borehole. For this reason, new techniques must be developed to evaluate oil and water flow rates in horizontal wells.

To determine the flow rates of the oil and water phases in a horizontal well, one must either 1) measure the individual oil and water flow rates directly, or 2) measure the individual oil and water velocities in addition to their holdups. (It should be noted that for most production logging applications in horizontal wells measuring only the holdup or only the velocity of the production fluids is usually insufficient to determine the source of production problems.) This paper will address the second approach dealing with the measurement of individual oil and water velocities and their holdups.

Oil and Water Velocity Measurement

Several existing technologies make it possible to measure water velocity in horizontal wells. The oldest of these uses a radioactive tracer such as Iodine-131 with an 8 day half-life. The iodine is placed in a water-soluble form. This material is injected into the borehole and then measured as it passes a gamma-ray detector. The time between injection and detection allows calculation of the flow velocity of the water.

This method can also be applied with some success to oil velocity measurements by placing the iodine into an oil-soluble form. The limitation in this approach is that the oil-soluble form is usually an emulsion that can exhibit some unique problems due to the nature of emulsions.

With the increased restrictions and risks associated with the use of radioactive tracers in the borehole, it is desirable to have a method of performing these velocity measurements without using radioactive tracers. This is one of the reasons that the WFL Water Flow Log was developed. This approach relies on the activation of oxygen in the water using a 14 MeV neutron generator and measures the transit time of the activated oxygen in the borehole giving a measure of the water velocity. Unfortunately, this method does not address the oil velocity measurement.

* Mark of Schlumberger
A new approach has been developed that is capable of independently measuring the oil and water velocities in horizontal wells without the use of radioactive tracers. The PVL* Phase Velocity Log uses a chemical marker for its measurement and is therefore a much safer approach to these velocity measurements. As in the radioactive tracer method, the chemical marker is injected into the borehole and then detected as it passes a sensor farther up the borehole (Fig. 1). The chemical marker can be placed in both oil- and water-soluble forms, neither of which is hazardous.

**Detection of Chemical Marker.** The chemical marker chosen for the PVL measurement uses a high neutron cross-section material and is detected by the RST* Reservoir Saturation Tool using a simple borehole sigma. Gadolinium has been chosen as the high neutron cross-section material since it has a 49,000 barn cross-section (more than 1000 times that of chlorine). This extremely high neutron cross-section makes it possible to minimize the amount of chemical marker needed for a measurement. The gadolinium is placed in a water-soluble form by dissolving GdCl₃ in water. The oil-soluble form of gadolinium has been achieved by the development of a new organometallic compound with low density, low viscosity, and high gadolinium concentration. The low density and low viscosity are important to ensuring that the oil marker disperses quickly in the oil.

The detection of the passage of the marker past the RST is accomplished by a borehole sigma indicator measurement. This is acquired in the inelastic-capture (IC) mode of RST operation where the neutron source is pulsed for 20 μs every 100 μs. This measurement does not give a calibrated value of borehole sigma since it is not corrected for background or formation sigma; however, it does give an indication of a change in borehole sigma with optimal signal/noise. This is all that is required since the PVL measurement is only interested in the time it took the marker to go from the injection point to the detection.

The borehole sigma indicator is acquired every 0.2 seconds; therefore, the maximum timing resolution is limited to this value. Because of diffusion and mixing of the marker with the flowing fluid, the length of time that the tool “sees” the marker can range from about 0.6 s to over 60 s depending on the actual fluid velocity.

Figure 2 shows some examples of the chemical marker detection for several fluid velocities obtained from the flow loop located at Schlumberger Cambridge Research in the UK. The figure includes data acquired with 0.2-s sampling superimposed with the same data after being filtered (to be described later). At lower fluid velocities, it takes longer for the chemical marker to pass by the RST tool and the signal is present for a longer period of time resulting in wider detection distributions as seen in the figure. In addition, at lower fluid velocities, the marker has more time to diffuse in the fluid of interest than at higher velocities. For this reason, at low velocities, the detected signal of the marker will be skewed to later in time. This is quite evident for the 12 ft/min measurement shown in the figure.

**Velocity Computation.** As shown in Fig. 2, the passing of the marker in the borehole is evident from the increase in borehole sigma. However, due to the short acquisition time of the data and the resulting statistics, the sigma indicator can be fairly noisy. For this reason, a Gaussian filter is used to reduce the data scatter but still maintain good marker timing information. The width of the filter can be varied with time after injection to take into account the effects of velocity and diffusion.

The next step of the data analysis is to determine when the marker was detected. This is achieved by simply looking for the highest value of the filtered borehole sigma indicator in the measurement. A quality indicator of this detection can be calculated by estimating the width of the detected signal and comparing this to the expected response. If the detected signal is too wide or too narrow, this could be indicative of some type of anomalous flow behavior (such as backflow) in the borehole.

Having determined the marker detection time, the time-offlight of the marker is calculated from the center of the marker injection. Velocity is then calculated by dividing the injector-to-detector distance by the transit time.

An error estimate of the velocity measurement can be made using the sampling time of the borehole sigma indicator. Since the sampling time is constant, the shorter the time-of-flight (the larger the velocity), the larger the percent error on the velocity measurement. Error on the velocity measurement can be reduced by increasing the injector-to-detector spacing.

**Flow Loop Results.** Laboratory experiments were performed in the flow loop facility to validate the measurement technique. The initial measurements were performed in single phase oil and water. Figure 3 shows the results of these measurements for velocities between 10 and 500 ft/min. The line on the curve is a linear fit to all of the acquired data. This fit had a linear correlation coefficient of 0.998 indicating an excellent fit. In addition, the slope and intercept of the fit were very close to unity and zero, respectively, indicating negligible bias in the processing algorithm.

**Tilting Loop Experiments.** A series of measurements was performed to demonstrate the changes in oil and water velocity as a function of well deviation (near horizontal). For these measurements, a fixed value of the water flow rate was chosen at 1500 BWPD. The oil rate was then varied from 750 to 3800 BOPD. The loop was tilted through a number of angles and the PVL velocity was measured in each phase. The angles used were nominally 85, 88, 90 and 92 degrees.

Figure 4 presents a series of plots showing the results. Lines have been drawn through the data points to help identify trends.

At angles below 90 degrees the flow is upwards. The oil travels faster than the water. At approximately 90 degrees deviation the oil and water travel at the same speed. Above 90 degrees down-flow is achieved and the water starts to travel faster than the oil. This is clearly seen on the plots except in the case of the highest oil rate (the bottom plot), where the phase velocities never quite cross over.
3-Phase Holdup Measurement

Pulsed-neutron tools have previously been used to qualitatively determine the 3-phase holdup in horizontal wells. This approach uses the borehole sigma and the inelastic near/far ratio for this determination. The method is considered qualitative, since tool calibration information is not available for the ratio measurement or the sigma of the gas.

Recent work reported by Peeters et al. has attempted to quantify the pulsed-neutron measurement for holdup in horizontal wells. Their approach utilizes three measurements from a single pulsed-neutron tool centered in the borehole: C/O windows ratio, borehole sigma, and capture near/far ratio. The measurements are combined through a linear response matrix to produce the desired holdup measurements. The coefficients for the matrix are determined by regression of modeled or measured tool responses to known conditions.

A more quantitative approach has been employed with the RST Reservoir Saturation Tool. This tool was primarily designed to measure the oil saturation of the formation without depending on formation water salinity. This was accomplished by using a carbon/oxygen (C/O) measurement. A large part of the problem of converting a C/O measurement into oil saturation, is the effect of the borehole on the measurement. In order to properly determine the formation oil saturation, the borehole composition must be known reasonably well. In general, a small error on the borehole composition can cause a 15% error on the formation oil saturation. For this reason, the RST tool was designed with 2 detectors to compensate for the borehole effect. However, from the previous statements, it is obvious that the RST tool can also measure the 2-phase borehole holdup in a well.

In addition to the obvious 2-phase holdup measurement, the inelastic near/far ratio is available from the RST tool and is sensitive to the presence of gas in the borehole. Quantifying this information and combining it with the already available C/O measurement provide sufficient information to quantitatively determine the 3-phase holdup in the borehole.

One of the biggest problems in characterizing the tool response for a 3-phase holdup measurement, is the acquisition of realistic data due to the difficulty and hazards of performing laboratory measurements with gas under realistic downhole conditions. Air is usually used to simulate the effects of gas for these measurements, however, real downhole gas has appreciable density and elemental constituents that cannot be ignored. Therefore, the tool characterization must depend heavily on tool response modeling (Monte Carlo). For this reason, this study included the use of laboratory data, Monte Carlo modeling, and field data to evaluate the 3-phase response of the tool. In addition, this evaluation was performed with the tool both centered and eccentered.

Laboratory Measurements. Measurements to characterize the RST-A tool response under conditions simulating a horizontal well with 3-phase holdup were performed at the Environmental Effects Calibration Facility (EECF) in Houston, Texas. This was done by dividing the borehole into 3 equal volumes and filling each section with either oil, water, or air. This simulated the effect of segregated fluids in the borehole. There are 10 possible combinations of these fluids under these conditions. Over 400 measurements were performed using various formations at the EECF. The formations were selected to provide variations in lithology, porosity, borehole diameter, and formation oil saturation. Most of these formations were run with the tool both eccentered and centered in the borehole.

RST-A Monte Carlo Model. Since laboratory measurements with realistic gas conditions are not possible in our laboratory formations, characterization of the tool response falls heavily onto tool response modeling. To benchmark the RST-A model, the laboratory measurements described above were modeled with MCBEND. MCBEND is a commercial Monte Carlo modeling code developed by AEA Technology in Winfrith, UK. The results from the modeling were then compared to the results obtained with the measurements, as shown in Fig. 5. These figures show that the modeling can be used to predict the tool response. Each figure has a line fit to the data which can be used as a calibration to convert from modeled results to measured results. Both centered and eccentered data are shown.

Borehole Gas Holdup. The inelastic near/far crossratio can be used to detect and quantify gas in the borehole. This is shown in Fig. 6 for a centralized tool. The gas was modeled as 0.3 g/ml methane (CH₄). The effect of porosity on the inelastic near/far ratio is small by comparison to its response to gas in the borehole. The data points along each gas holdup line lie high or low around the line depending on the “total hydrogen index” of the fluids in the borehole. For example, the 66% gas line has a lower near/far ratio for oil in the borehole than it does for water in the borehole. The figure also shows the non-linearity of the response if the changes from 0 to 33% gas are compared to changes from 66 to 100% gas. If the tool is eccentered (data not shown), the non-linearity is significantly worse.

2-Phase (Oil/Water) Holdup From C/O. As in the gas phase measurement discussed above, the positioning of the tool in a segregated borehole impacts the linearity and sensitivity of the holdup measurement. This section will address this issue with respect to the 2-phase, oil/water, situation with a near/far C/O interpretation approach. For this section, the interpretation approach utilized will be the standard RST approach. The data used for this section will include 6 points per formation porosity, i.e., oil and water in the formation with 4 different oil/water combinations in the borehole (see Table 1). The data points shown will be from modeling (the measured data show the same result).

In the normal RST processing, the coefficients for the interpretation model are calculated from the 4 endpoint measurements of the formation being considered (see Table 1). For this evaluation, the coefficients are still calculated in the manner described in the reference. These coefficients are then applied to the other 4 data points of the data set to look at the linearity effects with segregated borehole fluid. (This approach solves for both the oil saturation and holdup simultaneously). The results of this analysis can be seen in Fig. 7 for a centered and eccentered tool.
The top plot of Fig. 7 shows the reconstructed oil holdup for data modeled in a 7-in. casing (8.5- and 10-in. boresholes). The reconstructed holdup is extremely non-linear if the tool is eccentered. In this case, it appears that the tool does not see the top third of the borehole due to the non-linearity. If the tool is centered, the tool response is linear.

Since the effect being observed is a non-linearity caused by the tool's limited depth of investigation, the effect should be reduced in a smaller casing. The bottom plot of Fig. 7 shows modeled results for a 5.5-in. casing in a 8.5-in. borehole. As can be seen, the effect is reduced, but still an issue.

Table 2 summarizes the results of this 2-phase holdup analysis using this C/O interpretation. This table includes RMS accuracy estimates and 18-second precision for these measurements. From the data, it is obvious that a centered tool always gives better accuracy and precision than an eccentered tool. However, if the tool must be run eccentered, accuracy can be improved by making corrections based on calibrations of tool response as shown in the plots of Fig. 7.

The effect of this approach is reduced sensitivity to low oil holdups.

3-Phase Holdup Determination. To determine the holdup of all 3 phases using the near and far C/O ratios and the inelastic near/far ratio, a two-step interpretation is currently used (these could be combined into a single step). The interpretation is based on the assumption that the three borehole holdups sum to unity and that formation gas is zero, i.e., \( Y_o + Y_w + Y_g = 1 \) and \( S_o + S_w + S_g = 1 \).

The first step is to obtain the gas holdup from the inelastic near/far ratio (N/F). This is obtained from calibration data similar to those shown in Fig. 6 and can be expressed as:

\[
Y_g = f(\%)
\]

Once the gas holdup is determined, the water and oil holdups can be determined using a modified version of the normal RST C/O interpretation. The modifications made are to allow for the inclusion of gas holdup into the formulation as shown below:

\[
R_n = \frac{N_1 + N_2 \Phi S_o + N_3 \{Y_o + Y_w (\%)\}}{N_4 + N_5 (1 - S_o) + N_6 (1 - Y_o - Y_g)}
\]

\[
R_f = \frac{F_1 + F_2 \Phi S_o + F_3 \{Y_o + Y_w (\%)\}}{F_4 + F_5 (1 - S_o) + F_6 (1 - Y_o - Y_g)}
\]

where the \( R \)’s are the measured near and far C/O ratios; \( N \)’s and \( F \)’s are the near and far sensitivity factors of carbon and oxygen in the formation fluid, matrix, and borehole, and \( \rho_o \) and \( \rho_o \) are the downhole gas and oil densities. In these equations, the numerator and denominator have been modified from the original RST interpretation to allow for the contribution of gas in the borehole. In the denominator, this results in a reduction of the amount of oxygen present in the borehole. In the numerator, it is assumed that gas will increase the carbon response by a factor approximated by the relative densities of gas and oil.

As with the normal C/O processing, the sensitivity factors are obtained from laboratory calibrations which use the borehole size, casing size and weight, lithology, and porosity as inputs. Once the C/O ratios are measured and the gas holdup is calculated from equation 1, equations 2 and 3 reduce to 2 equations and 2 unknowns that can then be solved for the holdup and oil saturation.

In this formulation of the problem, it is assumed that the tool is equally sensitive to all sections of the borehole. As has been shown, this is a reasonable assumption if the tool is centered; however, if the tool is eccentered, this formulation will introduce some bias. Under many conditions, this bias can be removed by providing a correction based on data similar to Fig. 7.

3-Phase Holdup Results - Centered Tool. The interpretation procedure outlined above has been applied to the measured and modeled 3-phase data obtained in this study to evaluate the expected performance of this measurement. This includes the measured data (with air) and the modeled data (with air and 0.3 g/ml gas).

An example of the measurement parameters for a 16 p.u. oil-saturated limestone formation with an 8.5-in. borehole and 7-in., 23-lb/ft casing is shown in Fig. 8 in a 3-dimensional plot. In this plot, the corners of the plots represent the conditions when only a single phase is present in the borehole, i.e., \( Y_o = 1 \) is all water, \( Y_w = 1 \) is all oil, and \( Y_g = 1 \) is all gas (0.3 g/ml in this example). From one corner to another, the fraction of each phase changes linearly along that line. The point in the center of the plot has water, oil, and gas present in equal fractions. The \( z \) axis of the plot shows the magnitude of the various parameters being displayed.

The data from Fig. 8 are from modeling since a realistic gas was used (0.3 g/ml). As can be observed, the modeled data are dominated by the physics of the measurement, while the statistics of the Monte Carlo calculations are small by comparison. This makes identifying the tool response trends fairly straightforward. Also note that the inelastic near/far ratio response is quite orthogonal from the other responses, giving a clean gas signal. The near and far C/O ratios show a similar response; however, they are orthogonal enough to differentiate the borehole and formation signals.

When the holdup data of this study are analyzed through the above interpretation model, the predicted holdups can be compared to the known holdups to give an estimate of the accuracy of the approach. An example of these errors in reconstruction are shown in Fig. 9 for the input data of Fig. 8. These data show that the reconstruction is fairly good. The overall accuracy of this approach can be estimated by taking RMS errors of the data. This was calculated using data for several formations with different borehole size, porosity, and saturation. This resulted in RMS errors of 6.3, 6.1, and 4.8% for the gas, oil, and water holdups, respectively.

While performing the holdup calculations, it is possible to estimate the precision of the holdup measurement by propagating the measurement errors through the analysis. This was done assuming 18 seconds of data accumulation for the measurement, which is equivalent to logging at 500 ft/hr using a 5-level depth average. For these conditions, the 1/3σ
precisions were estimated to be 1, 15, and 15% for gas, oil, and water holdup, respectively. These precisions will vary depending on the formation porosity, borehole size, and casing size.

It is recommended that holdup measurements in horizontal wells be performed in conjunction with velocity measurements for an unambiguous interpretation. Since the velocity measurements are stationary measurements, a holdup measurement could be performed at the same time as the velocity measurement, giving more than adequate precision to the measurement.

Field Test Results

Field Example 1. This North Sea horizontal well was completed with a 6 5/8-in., 66-lb/ft liner that was cemented into place to give good isolation. This well was producing water and one of the objectives of the production logging program was to identify the source of the water. Fig. 10 shows a partial set of data from this well. The top graph in the figure shows the water velocity measurements from PVL compared to those from WFL. The agreement is excellent between the two techniques for the few depths that were repeated with both measurements. The next graph down shows the oil velocity measured with the PVL, followed by a graph of the water holdup measured by the LIFT Local Impedance Flowmeter Tool. The LIFT tool measures the water holdup in a wellbore by scanning across the wellbore with 6 separate impedance probes which individually measure the local water holdup. In both conventional and horizontal wells the data from these 6 probes can be processed to give a global water holdup measurement. (Unfortunately, since the inelastic measurement was not run in this well, holdup results from C/O are not available). The bottom graph in the figure shows the oil and water flow rates calculated from the velocities and holdup. These data indicate that most of the water production is from below 850 ft while most of the oil is also being produced from below 550 ft. Because of the completion used in this horizontal well, it is possible to isolate the lower zone of this well using a bridge plug, which the operator plans on doing.

If one tried to interpret this well based only on the velocity data, one might conclude (erroneously), that there was a large influx of water at 600 ft due to the increased velocity. Trying to base the interpretation only on the holdup information is difficult since several interpretations are possible. However, the combination of the velocity and holdup data leads to the only reasonable interpretation.

Field Example 2. This well was commissioned in 1993 as the first well in the offshore section of this reservoir (18 p.u. sandstone). The well has been on continuous production since then, with the only interruptions for workovers. Immediately prior to logging, the well was shut-in for 33 days to permit the workover of another well. The horizontal section was drilled with a 8.5-in. bit and completed with a 5.5-in., 17-lb/ft casing and cement. The well inclination across the reservoir section varies from 75 to 88.5 degrees. It penetrates the original OWC, enabling movement of the OWC to be monitored. The objectives of the production logging program were to 1) determine the flowing production profile and 2) determine the source of the water production.

Both velocity measurements and holdup measurements were performed with the RST tool in this well. Unfortunately for this study, the well did not have any gas in the borehole (as verified by the inelastic data). However, it is an excellent example of 2-phase oil/water production in a horizontal well and is still a good example of what can be accomplished in a horizontal well.

The RST tool was run eccentric in the borehole for this well. As mentioned earlier, if not corrected, this results in some bias in the final holdup estimates. For this example, the biases were removed by a calibration similar to that shown in Fig. 7 (derived from modeling). The RST holdup interpretation was based solely on modeling results.

The logging results are shown in Fig. 11. The top graph in the figure shows the comparison of PVL and WFL water velocity measurements. The agreement between the two techniques is excellent. (The large error bars on the two measurements in the upper part of the well are due to the short measurement times for these individual WFL measurements, while the smaller error bars are from the PVL). The next graph down shows the oil velocity measured with the PVL. The following graph shows a comparison of RST-A and LIFT water holdup measurements. The agreement between the two techniques is excellent except where known problems occurred with the LIFT measurement. (Note, the uncalibrated LIFT points were due to operational problems and the over-ranged point was past the maximum LIFT sensitivity). The bottom graph in the figure shows the oil and water flow rates calculated from the velocities and holdup. These data indicate that most of the water production is from below 900 ft while the oil production is fairly uniform over the interval.

This log is an example of when the holdup answer, by itself, is unambiguous, and why the addition of velocity information is usually required for an accurate interpretation. Looking at only the holdup data from this well, one just observes a rather uniformly decreasing water holdup as you go up the well. This, in itself, does not readily identify that most of the water production is coming from the lower part of the well.

Summary and Conclusions

A new approach to obtaining oil and water flow rates in producing horizontal wells has been developed using a chemical marker in combination with a pulsed-neutron tool. This approach uses separate measurements of oil and water velocities in combination with separate holdup measurements to obtain the flow rates.

The PVL method measures both the oil and/or water velocities using chemical markers rather than radioactive tracers. Because of this, it is believed radioactive tracers do not need to be used for these velocity measurements and that they can be replaced with the inherently safer chemical marker techniques. This approach would simplify regulatory concerns, ease procurement of services, and remove
radioactive material from the downstream oil and water handling facilities providing for an overall more efficient and safer operation.

To prove the viability of the PVL measurement, flow loop tests were carried out in single- and two-phase (oil/water) flow conditions. The two-phase results demonstrated the ability of the velocity measurement to separately measure the oil and water flow velocities in segregated flow. It also reaffirmed the notion that velocity or holdup measurements, by themselves, will not always give a correct representation for production problems, but that holdup and velocity measurements together can.

Field tests have demonstrated the success of the new velocity measurement by means of comparison to another independent velocity measurement, the WFL technique. The agreement between WFL and PVL data for water velocity determination was excellent and adds credence to the oil velocity measurement for which there is no other acceptable measurement technique (except possibly radioactive tracers).

The ability of the RST-A tool to measure 3-phase holdup in horizontal wells has been quantified in terms of accuracy and precision of the measurement. This has been accomplished by merging experimental (using air to simulate gas) with modeled data (using 0.3 g/ml CH₄ for gas) into a database with over 406 borehole/formation conditions. This approach has allowed for the benchmarking of the Monte Carlo model (for the inelastic measurement) and predictions of the tool response with gas under realistic downhole conditions.

The inelastic near/far ratio was shown to be an excellent stand-alone indicator of gas holdup. This measurement is more accurate with the tool centralized in the borehole than when it is eccentric due to non-linearities caused by tool positioning.

The 2-phase holdup (oil/water) measurement was evaluated using the near and far carbon/oxygen ratios for the effects of tool positioning. This analysis was the normal dual detector C/O analysis but used to evaluate the non-linearities in the measurement due to segregated flow. These results indicated that the tool response could be non-linear if the tool was run eccentric with segregated flow, but that it could also be corrected over a large part of the dynamic range with proper calibration. It was also shown that running the tool centralized in segregated flow does not exhibit this non-linear behavior.

A fully integrated 3-phase holdup analysis was evaluated using the inelastic near/far count rate ratio and the near and far carbon/oxygen ratios. This analysis was performed using a RST analysis modified to take into account the gas contribution. The analysis used both measured and modeled data in combination for a centralized tool. For this analysis, the estimated accuracies are approximately 6 p.u. for each of the three phases. The estimated precisions (18 seconds of data) for this measurement are approximately 1, 15, and 15% for the gas, water, and oil holdups, respectively.

The field example indicated the accuracy and precision of the 3-phase holdup measurement are in line with the predictions from the modeling. Comparison of the holdups obtained with the RST tool compared quite favorably with holdup measurements performed by another totally independent technique, establishing the validity of both measurements. In addition, this field test demonstrated that modeling results could be used to interpret log data accurately.

Finally, the field examples shown reaffirmed the notion that velocity or holdup measurements by themselves will not always give a correct interpretation of production problems, but that holdup and velocity measurements together can.

Acknowledgments

The authors would like to thank British Petroleum and Amoco for permission to publish their data, and appreciation to Steve Bamforth and Cecile Benestad for their assistance in obtaining this permission.

Nomenclature

- \( \phi \) = Porosity
- BOPD = Barrels Oil Per Day
- BPD = Barrels Per Day
- BWPD= Barrels Water Per Day
- C/O = Ratio of Carbon to Oxygen
- N/F = Inelastic Near to Far Ratio
- O/WC = Oil/Water Contact
- RMS = Root-Mean-Square
- \( S_o \) = Formation Oil Saturation
- \( Y_o \) = Oil Holdup
- \( Y_g \) = Gas Holdup
- \( Y_w \) = Water Holdup

SI Metric Conversion Factors

- \( \frac{BPD}{1.589873} = \frac{E-01}{m^3/d} \)
- \( \frac{ft/hr}{8.466667} = \frac{E-05}{m/s} \)
- \( \frac{ft/min}{5.08} = \frac{E-03}{m/s} \)
- \( \frac{in.}{2.54} = \frac{E+00}{cm} \)
- \( \frac{lb/ft}{1.488164} = \frac{E+00}{kg/m} \)

References


- 588 -
Table 1: Fluid combinations used with the data for 2-phase holdup calculations from C/O. The holdup combinations used simulated segregated borehole holdup in a horizontal well. Those combinations used for calculation of interpretation coefficients are labeled as 'endpoints'.

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<tr>
<th>Endpoint</th>
<th>S₀</th>
<th>Y₀</th>
<th>Yₑ</th>
<th>Fluid combination used with data for 2-phase holdup calculations from C/O. The holdup combinations used simulated segregated borehole holdup in a horizontal well. Those combinations used for calculation of interpretation coefficients are labeled as 'endpoints'.</th>
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Table 2: Accuracy and precision (18 second) of the RST-A oil holdup measurement, Y₀ for the tool eccentric and centered in the borehole with several casings and segregated borehole fluids. This analysis solves for S₀ and Y₀ at the same time.

<table>
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<th>Porosity (p.u.)</th>
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<td>7</td>
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<td>16.32</td>
<td>5.5</td>
<td>8.9</td>
<td>14-45</td>
</tr>
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Fig. 1: Pictorial showing the basic PVL measurement. The injection tool injects into the borehole chemical marker that disperses in the fluid of interest (oil in this example). The chemical marker travels in this fluid until it is detected by the RST tool as a momentary increase in the borehole sigma. The fluid velocity is calculated by dividing the distance traveled by the transit time.

Fig. 2: The borehole sigma indicator for various flow velocities as measured by the PVL tool in the flow loop. The data are acquired with 0.2-s sampling. The light lines show the raw data and the heavy lines show the filtered data. This figure shows data at very low velocities where the skewing due to diffusion is much more noticeable.

Fig. 3: PVL measurement velocity versus calibrated flow loop velocity for single-phase brine and oil measurements. The error bars represent an error due to a 0.2 second timing error.

Fig. 4: Oil and water velocities measured by the PVL tool with 2-phase flow where the water flow rate was kept constant at 1500 BWPD in the flow loop. 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. From this, it is obvious that small deviations from horizontal can cause large changes in the measured fluid velocities.
Fig. 5: Near C/O ratio, far C/O ratio, and inelastic near/far ratio from measurements versus the MCBEND modeled results. The line shows a linear fit to both the eccentered and centered tool data.

Fig. 6: RST-A inelastic near/far countrate ratios as a function of porosity modeled in IC logging mode. The tool was modeled centered in a 7-in., 23-lb/ft casing in both 8.5- and 10-inch boreholes. Gas was modeled with a density of 0.3 g/ml. The lines are drawn to show the trends in the data for various gas holdups.

Fig. 7: Reconstructed holdup from modeled data where the interpretation coefficients were calculated from the endpoint measurements in 7- and 5.5-in. casing. These data include only oil and water in the borehole and formation. The interpretation solved for both \( Y_o \) and \( Y_w \) simultaneously. The line is drawn to indicate perfect reconstruction.
Fig. 8: Modeled response of the RST-A tool to changes in segregated borehole fluid composition for a 16 p.u. limestone formation with a 8.5-in. borehole and a 7-in., 23-lb/ft casing. The data were modeled using gas with a density of 0.3 g/ml.

Fig. 9: Error in the reconstruction of borehole holdups using the modeled data of the RST-A tool. The formation used for this analysis was a 16 p.u. limestone formation with a 8.5-in. borehole and a 7-in., 23-lb/ft casing. The data were modeled using gas with a density of 0.3 g/ml.
Fig. 10: Example of production logging measurements performed in a horizontal well with a 6 5/8-in., 66-lbf/ft liner (4.4-in. ID). The liner was cemented in place and perforated at various intervals. The measurements include water velocity measurements from PVL and WFL tools, oil velocity measurements from PVL tool, and holdup measurements from the LIFT tool. The lines on the plot connecting the data have been added to help identify the trend.

Fig. 11: Example of production logging measurements performed in a horizontal well drilled with a 8.5-in. bit and completed with a 5.5-in., 17-lbf/ft cemented casing. The measurements include water velocity measurements from PVL and WFL tools, oil velocity measurements from PVL tool, and holdup measurements from RST and LIFT tools. The lines on the plot connecting the data have been added to help identify the trend.