PLANNING SUCCESSFUL HORIZONTAL PRODUCTION LOGGING INTERVENTIONS
(or, how to avoid unpleasant post mortems)

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ABSTRACT

In open hole logging the variability in the logging environment is relatively limited and choosing the appropriate formation evaluation sensors comes down to avoiding the use of sonic logs in air/gas filled boreholes and being aware of the mud resistivity when selecting an induction or laterolog tool.
By comparison, production logging involves handling many orders of magnitude of downhole velocity, large variations in flow regime, many different completion strategies, and, in the case of horizontal wells, a big problem with the standard spinner velocity measurement used in vertical and deviated wells. Because of this large variability in the downhole environment it is very easy to record measurements which are un-interpretable.
This paper looks at the techniques required to simulate the downhole logging conditions, then considers the various sensor technologies and finally shows how the correct toolstring is chosen and a logging program written.

INTRODUCTION

In open hole logging the variability in the logging environment is relatively limited. Rock density and porosity have a relatively small dynamic range and as long as the obvious pitfalls of logging in an over-sized hole are avoided we can expect to see a good density neutron log. Sonic propagation velocities vary by less than an order of magnitude and as long as gas or air filled boreholes are avoided a logging tool should be able to deliver a velocity. Formation resistivity is perhaps the most challenging measurement in terms of the dynamic range encountered but even here the choice has usually come down to ensuring that the resistivity tool is compatible with the mud system.
By contrast, in production logging in cased hole, it is much easier to record an un-interpretable log. Downhole mixture velocities can be too high, or too low, or sometimes both! The holdup of the phase of interest may shrink until it is too small to be resolved. Increasing well deviation degrades and eventually eliminates certain technologies. Nuclear holdup techniques may be incompatible with the completion system and the well may not be as stable as is needed.
Therefore production logging in general, and horizontal production logging in particular, need a rigorous pre-job downhole simulation, an honest evaluation of the available sensors, and an impartial recommendation of the best toolstring for each well.

THE DOWNHOLE ENVIRONMENT

In any production logging operation the first thing we look at are the measured surface rates (or the expected surface rates in the case of an exploration well). For the purposes of planning, the water shrinkage can be approximated to 1.0, oil shrinkage (except for the lightest of light oils or condensate) can be approximated to 1.3 or 1.4, and only gas (after subtraction of the solution gas) needs the flowing bottom hole pressure and temperature in order to compute the ideal gas shrinkage factor, Bg.
In the absence of any guidance to the contrary the inflow profile is assumed to vary linearly from the heel to the toe of the well.
The next step in a horizontal well is to look at the variations of true vertical depth along the well path together with the location of any perforations, sliding slide doors, or lateral windows.

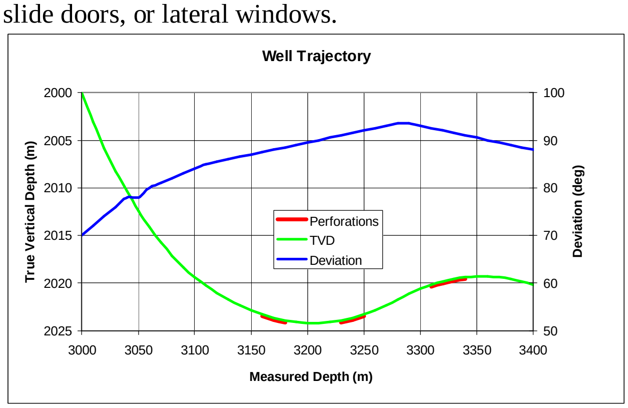

Figure 1 - Well Trajectory Plot

In a horizontal well the difference between 89 degrees and 91 degrees deviation can have profound differences on the dominant phase holdup and the flow regime.

Flow regime maps derived from low pressure surface measurements can be used as a rough guide to the expected downhole conditions.

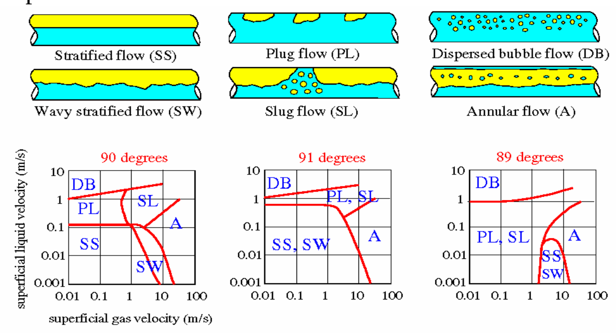

Figure 2 – Typical Flow Regime Map

One piece of important information not introduced yet is the cross-sectional flowing area. Usually this can simply be read off a completion schematic unless there is a slotted liner or screen completion.
With screens there will probably be some kind of external casing packer or flow diverter that will periodically return all the flow to the inside of the completion, however, in the case of a slotted liner there will probably be significant flow rates in the annulus. Flow loop experiments using dye and various mixtures of oil, water, and gas show that, except at very high velocities, the annulus velocity is approximately equal to the internal velocity. In some cases the phase of interest may travel exclusively in the slotted liner annulus.

THE OBJECTIVES

One good way to fail an examination is to fail to read the question and to answer a question that was not asked. The same is unfortunately true of production logging. If the logging company assumes that they know the objective of the logging operation then there is ample scope for disappointment when the interpretation report is finally delivered. It is therefore important that a meaningful objective(s) is provided by the oil company. The often seen, “The objective is to record a production log”, is not particularly helpful. What is required, is the use to which the production interpretation report will be put. The production logging planner will appreciate objectives such as;

1) to identify water entry points with a view to setting a water isolation plug,
2) to compute layer pressures from a multi-rate production log,
3) to identify zones of bypassed oil for re-perforation.

OTHER CONSTRAINTS

A common constraint in the North Sea is the requirement to rig up under the rig floor. With a limited space available for both pressure control equipment and the production logging tool string this leads to either a very short toolstring or the use of pressure deployment bars.
On longer reach horizontal wells we may not be able to carry a logging cable inside the coiled tubing due to the increased weight and earlier lock up. In this case the production logging tools may be required to work in memory mode.
The use of conventional wireline tractors means that the logging tools are turned off while tractoring in hole and can only be powered up while pulling out of hole. This has implications for spinner surveys and probe based holdup measurements.

SENSOR SUITABILITY FOR HORIZONTAL WELLS

In no particular order the following sensors have been evaluated;

Temperature. In a horizontal well, geothermal gradients will be very small to zero. Therefore various second order effects become more pronounced.
Joule Thompson cooling will be visible as long as there is a near wellbore skin, however, slotted liner and screen completions very often result in low values of skin. Similarly high skin liquid entries will often show a significant heating effect. Frictional pressure drops in high velocity wells will be apparent as a gentle heating effect.
Hot spots on the production logging tool housing will sometimes leave an anomalous signature in a stagnant toe as a tool is reconfigured from tractoring to logging.
Quantitative temperature flow rate analysis is usually impossible.

Pressure. With little or no change in true vertical depth there is no useable pressure gradient to convert into a density. In extremis a monophasic frictional pressure drop can be converted back into a flow rate.
Quantitative pressure flow rate analysis is usually impossible.

Spinner/Turbine. The assumption, that a spinner averages the velocities (or momentums) of the phases present, works well in vertical wells, begins to struggle in a lot of deviated wells and usually fails in a horizontal well. This is because of the high stratification, extreme holdups, and large slip velocities encountered in many horizontal wells. Only in very high velocity wells does the slip velocity become

negligible and the spinner velocity tend towards the mixture velocity.
Sometimes, depending on the downhole conditions, we may find that the spinner is totally immersed in just one phase. Under these conditions the spinner velocity may correspond to the velocity of the water, for instance. However, these lucky occasions should not be depended on.
Recently we have seen the development of tools with multiple mini-spinners designed to exploit the opportunities for single phase logging. The small diameter of a mini-spinner delivers a very small torque and requires specialised blade profiles and bearing technology to keep the spinner threshold velocity down to useable level and deliver an interpretatble velocity array.

Oxygen Activation. High energy neutrons are used to activate any oxygen in the near vicinity. Activated oxygen decays back to ordinary oxygen by the emission of gamma rays and with a half life of 7.2 seconds. Flowing water will therefore carry a gamma ray signature that decays with time from the neutron activation. Using either a neutron burst and a single gamma ray detector or a continuous neutron flux and two gamma ray detectors the velocity of the water can be determined. This is a very powerful technique for use in horizontal production logging.
In the case of slotted liners, and to a lesser extent, screens, the oxygen activation log will detect both completion flow and annulus flow. Sometimes the two can be confused and/or interfere with each other.

Markers. The case of oxygen activation is merely a sub set of the general marker technique. Markers can be radioactive or non-radioactive. Whilst water soluble markers are relatively simple to engineer, it is much more difficult to create an oil soluble marker that works at downhole temperatures. To date there are no markers that can be used for measuring a downhole gas velocity.

Nuclear Fluid Density. The principle here is to use a chemical gamma ray source and a gamma ray detector. A high gamma ray count rate means a low density fluid whilst a low gamma ray count means a high density fluid.
One type of nuclear density tool uses gamma ray attenuation across a small window in the tool body whilst the other type uses internal shielding to avoid attenuated gamma rays and uses scattered gamma rays to sample a larger pipe area. Unfortunately the attenuation technique delivers only a pipe centreline density while the scattering approach usually sees beyond the casing and supplies completion and formation information mixed in with the density. Typically, neither approach delivers quantitative holdup information for a horizontal interpretation.

Pulsed Neutron Holdup. The Carbon Oxygen technique used for formation saturation logging can be adapted for wellbore holdup logging. In this application the carbon oxygen signal is driven primarily by the carbon inside the wellbore oil and gas while the oxygen responds to the water. Gas is usually detected by the inelastic gamma ray ratio between a near and far detector.
Key to understanding whether a particular logging tool is delivering calibrated answers is the ability of the tool to extract spectral yields and the existence of a tool characterisation database that includes the same casing size, casing weight, and to a lesser extent the same lithology and porosity. If these two conditions cannot be satisfied then the log interpreter only has curves which respond to changes in holdup.
In the case of a slotted liner completion this measurement will see into the high side annulus albeit with a reduced sensitivity and accuracy.
Pulsed neutron carbon-oxygen derived holdup is a very powerful technique for horizontal production logging.

Probe Holdup Measurements. Currently there exist probe holdup measurements based on electrical conductivity, electrical capacitance, and optical reflectance. Because a single probe in a horizontal well will not deliver a representative holdup a number of identical probes are arranged along either a vertical line (from the top to the bottom of the pipe) or along a circle centred on the pipe axis. Some probe tools also allow the probes to be scanned to improve the pipe coverage.
The twin aims of ruggedness and accuracy cannot easily be satisfied with a probe holdup measurement. Larger stronger probes suffer more from preferential wetting or blinding while smaller probes can easily be broken in a barefoot completion. For electrical probes the choice of conductor, insulator, and excitation frequency will also affect the quality of the holdup measurement.
Most probe based holdup measurements provide better results when logged down against the flow or when logged upwards in a high velocity well. This means that a conventional tractor (no logging down) in a low velocity well should not be expected to deliver good probe holdup data.
Probe holdup measurements will also suffer from bubble shearing in turbulent flow rendering the discontinuous phase bubbles too small to be recorded. Smaller probes can accommodate more bubble shearing than larger probes.
Asphaltenes can be encountered in a well when injection gas breakthrough first occurs. Asphaltene will

blind a probe by covering it with a thin insulating and optically opaque skin.
Good probe holdup measurements are very useful in horizontal production logging.

Flow-through holdup measurements. There are a number of flow-through mandrel type holdup tools working on a number of physical principles. However, as they normally only sample the centreline holdup they do not provide usable holdup data in the extreme stratification of most horizontal wells.

Slip Models. Although not a measurement, a slip model will provide an extra velocity and therefore can replace the need for an extra measurement. Unfortunately, a lot of slip models have evolved from vertical experiments and fail absolutely in horizontal wells. Of the slip models that are actually designed for horizontal wells, the development driver has normally been to predict pressure drop along the wellbore; the slip velocity is provided as an afterthought. Today there are a handful of horizontal gas-liquid slip models and still fewer horizontal three phase slip models.
The accuracy of slip models under downhole pressures and in large large diameter pipe conditions is not known, however, empirical experience suggests that errors of 50% are easily possible.

SENSOR EVALUATION AND SELECTION

With so many different measurement techniques it is impractical to run everything in every well. There has to be some sensor selection based on information theory. At a minimum the toolstring sensors should satisfy the following requirements.

1) To log a single phase well there is no need for holdup information and but one velocity is required.
2) To log a two phase well there is a need for one holdup measurement and two velocities (although one velocity can be replaced by a slip model).
3) To log a three phase well there is a need for two holdup measurements and three velocities (although two velocities can be replaced by slip models).

Alternatively this can be expressed as, to log n-phase flow requires n velocity measurements and n-1 holdup measurements.
Taking the case of a simple horizontal gas-water well figure 3 shows how the estimated downhole conditions are compared against a set of available sensors.

	Top 100% Flow	Middle 50% Flow	Bottom 10% Flow	
Depth (m)	4100	4500	4750	
Mixture Vel (m/s)	1.61	0.80	0.16	
Water Holdup Yw	40%	15%	10%	
Gas Holdup Yg	60%	85%	90%	
Flow Regime	PL, SL	SS, SW	SS, SW	
Deviation (deg)	87.6	91.0	90.2	
2 1/2" fullbore spinner	80%	50%	20%	Mixture Velocity
2 1/8" Tubing Spinner	80%	45%	15%	Mixture Velocity
Oxygen Activation Log	90%	90%	90%	Water Velocity
Petalas & Aziz	40%	40%	40%	Gas-Liquid Slip Model
Vertical Mini-Spinner Array	80%	90%	90%	Water & Gas Velocity
4 Optical Probes	50%	50%	50%	Gas Holdup
8 Optical Probes	80%	80%	80%	Gas Holdup
4 Electrical Probes	50%	50%	40%	Water Holdup
8 Electrical Probes	80%	80%	80%	Water Holdup
Pulsed Neutron Holdup	70%	70%	70%	Three Phase Holdup
Vertical Array of Optical Probes	90%	90%	90%	Water Holdup
Vertical Array of Electrical Probes	90%	90%	90%	Gas Holdup

Figure 3 - Sensor Comparison Table

Because this is a case of two phase flow, two velocities are required. These can come from the oxygen activation log and the Petalas & Aziz slip model or from the mini-spinner array; other combinations offer inferior (and unacceptably low) quality.
Only one holdup measurement is needed and this can come from 8 electrical probes or 8 optical probes or a vertical array of optical and electrical probes or a pulsed neutron CO based holdup.
Two obvious solutions to logging this well therefore present themselves.

1) A pulsed neutron tool providing both holdup and water velocity in combination with a gas-liquid slip model.
2) A vertical array of mini-spinners and holdup probes.

Option 1 will probably be more rugged while option 2 will be more accurate.

THE LOGGING PROGRAM

Making a production log in a horizontal well typically involves much longer logging intervals than traditional vertical or deviated wells. In addition there will be wireline tractors or coiled tubing and probably, the presence of novel sensors with special logging requirements.

Therefore a logging program needs to be designed that eliminates redundant logging passes and increases logging speeds whilst also including the stations and scans of the special tools. If the rig up requires pressure deployment and/or coiled tubing then the possibility of tool failure, excessive lost time, and even a cancelled logging job, may require the flowing survey to be brought to the start of the data acquisition.

CONCLUSION

For planning production logging in general and for horizontal production logging in particular a successful logging operation depends upon;

1) a simulation of the downhole conditions,
2) an understanding of the objectives,
3) the availability of sensors suitable for a horizontal well,
4) a technical evaluation of the sensors (usually by a log analyst),
5) a customised logging program..

ABOUT THE AUTHOR

Colin Whittaker is a graduate of the Imperial College of Science, Technology & Medicine and a Fellow of the Institution of Electrical Engineers. He has worked in the field of production logging as a Schlumberger logging engineer for 9 years, in production logging research for 3 years and for 9 years as a production log analyst.
He is currently an Engineering Advisor on Production Logging and Interpretation.