FORMATION TESTING AND SAMPLING IN LOW-MOBILITY FORMATIONS: AN EXAMPLE OF NEW TECHNOLOGY SOLUTIONS

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ABSTRACT

A wireline formation pressure testing and sampling program was planned for a new exploration well in a sandstone reservoir. Using information from six offset wells, the reservoir was expected to exhibit reasonable porosity and permeability with either oil and/or gas present.

The well was drilled with oil-based mud (OBM) across the reservoir section. Whilst drilling one of the upper sands, significant mud losses occurred, requiring the use of loss control material (LCM) to cure the losses. A full evaluation suite was performed over the reservoir section, including the zone that encountered losses. Log results indicated the presence of formation water and oil. The wireline-formation-pressure testing and sampling program used a pump-through system and fluid analyser to monitor the flowing fluids over this zone of interest. The real-time analysis identified a mix of OBM filtrate and formation water. The formation testing tool was configured with a standard probe and an elongated packer. A fluid sample was acquired, and when analysed, it contained hydrocarbons and formation water. Based on the results from the fluid sample, the real-time fluid analysis was re-evaluated. An emulsion likely developed across the mud-loss zone, affecting the fluid analyser data.

The well was side-tracked as per the original plan. Because of the low mobilities encountered in the lower section of the main bore, changes were made to the formation testing and sampling equipment. These changes incorporated a new concentric flow packer that was designed to evaluate the low-mobility zones without needing large-flow-area inflatable packers. The extra-elongated packer was used for pressure testing instead of the standard packer.

Use of advanced deployment-risk-management technologies prevented a costly fishing operation in challenging hole conditions after completion of the pressure testing program. The pressure data set showed a very low permeable formation, where mobilities were between 0.3 and 3.0 mD/cP, and thus very challenging for any fluid and pressure sampling configuration. After a wiper trip, the fluid sampling run was conducted using the new, large-flow-area concentric packer to obtain a water sample, completing the pressure and fluid sampling program. The use of the new concentric packer substantially reduced the breakthrough time of the formation fluid compared to the conventional packer system used on the main bore and resulted in low contamination samples.

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Low-permeability reservoirs can be extremely difficult to acquire reliable data and evaluate it; in particular challenging for pressure stabilisation and the quality of the pressure data point. However, the new technology solutions, using the extra-elongated packer ensured substantial pressure data collection and more pressure stations with higher reliability and quality. Fluid samples were collected using the new concentric packer, and contained low contamination levels, enabling a full evaluation of the reservoir, a task that would be very challenging using conventional formation testing and sampling equipment.

INTRODUCTION

An exploration well with a main bore and a sidetrack was planned to test the presence of upper Jurassic sands and hydrocarbon in a prospect in the Norwegian Sea, Norwegian Continental Shelf. An extensive wireline data-gathering program was planned for both wellbores including extensive formation pressure and fluid sampling. Based on information from six offset wells, the reservoir was expected to exhibit reasonable porosity and permeability with either oil and/or gas present. The data gathering program was planned accordingly to these expectations.

The reservoir sections of both wellbores were drilled with OBM and an 8.5-in bit. Whilst drilling the main bore, losses were encountered in the upper section of the well. The losses were cured before the well was drilled to a depth of XX85 m. Because of well and operational conditions, an intermediate wireline data-gathering program was performed before further extending the well to a total depth of XX85 m. One of the key objectives of the well was to identify reasonable upper Jurassic sands; however, the reservoir quality was poorer than expected in the lower section of the main bore.

CASE HISTORY

The main wellbore was drilled with 1.5 g/cc OBM initially with an 8.5-in bit and reached a depth of X065m. The initial logging campaign comprised five logging runs to evaluate the formation properties. Acoustic and resistivity imaging and petrophysical and acoustic logs were logged prior to the formation testing and sampling run. Those were followed by nuclear magnetic resonance and elemental spectroscopy logs, and rotary side wall coring. The logs were run down to XX60m and formation pressure and sampling points were picked from them. The formation testing and sampling run comprised of two conventional probes equipped with a standard packer and the elongated packer (**Fig. 4**), which has a flow area three times larger than the standard packer. The fluid analysis was conducted by the fluids analyser, which measures optical density, fluorescence, refractive index, density, viscosity, sound speed and calculates GOR and compressibility of the flowing fluid through the tool. The tool was equipped with three tank carriers enabling eighteen fluid capturing chambers to be run. Forty two stations were planned for pressure testing with twenty seven good tests and repeats, twelve tight/supercharged, three no seals and four post-sample tests.

Whilst drilling through the upper part of the upper Jurassic sands, losses occurred. Large amounts of LCM were required to cure the losses and the mud weight was reduced to 1.4 g/cc before drilling further. The pressure testing through the zone resulted in difficulty validating a useable gradient because of the losses unseating the "initial" fluid conditions and association saturation levels. The mobilities observed were reasonable; however, the dominating fluid density was questionable and the losses meant the potential to get a representable sample became even more difficult in this affected zone. One sample station was collected in the zone.

In the lower section of the well, three sample stations were collected. Because of very poor mobilities, the sampling times were long, up to 9 hrs. One particular problem was the length of time it took to observe the first water slugs, This problem occurred because the pump speed was very slow because of the low mobility and depth of invasion (DOI), and it took more than 130 minutes before a full water slug appeared through the Fluid Analyser (**Fig. 1**).

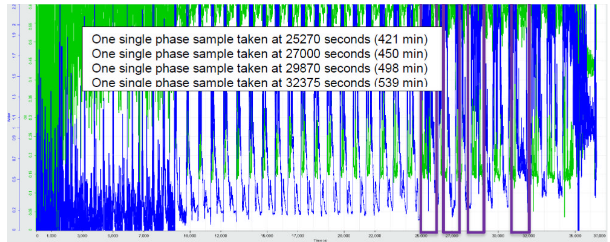

Fig.1 Oil (green)/water (blue) optical density vs time plot – slug flow

The loss zone sampling from the upper section of the main bore resulted in an extremely interesting and complex fluid analysis. The initial pumpout showed an increasing water cut after approximately 2,000 seconds; however, the typical oil/water slug effect that occurs in this type of environment, which was seen on the previous points didn't occur (**Fig 1**.). The oil fraction decreased (**Fig. 2)** and the density measurement increased steadily to approximately 0.95g/cc (**Fig. 3**). The density measurement became fairly flat and three consecutive sample bottles were filled. Upon opening the tanks, formation oil was seen along with the other fluids and solids. The real – time data was reevaluated and found that an emulsion of formation oil, water, OBM filtrate and LCM was flowing at the time of sampling.

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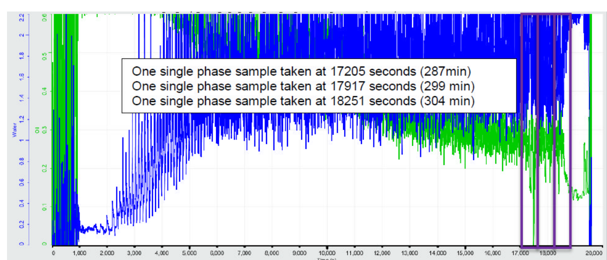

Fig.2. Oil (green)/water (blue) optical density vs time plot.

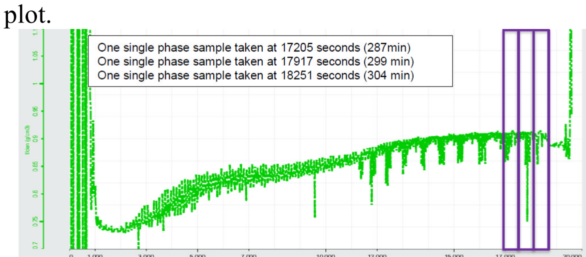

Fig.3. Tuning fork density vs time plot, highlighting stabilisation at the time of filling the tanks.

The well was extended deeper after the intermediate logging program, and further evaluation was conducted in the deeper section. The mobility of the lower section was very low; therefore, the formation testing and sampling string was subsequently revised and configured with two conventional probes, one with an elongated packer and the other with an extra-elongated packer (**Fig. 4 and 5**). Eighteen depth stations were conducted, resulting in eight good tests (including five repeats), five tight/supercharged tests, four still building up pressure and one test with no seal. The sampling was conducted in a 1mD/cP rock and pumping took approximately 7.5 hrs with pumping rates of approximately 1cc/sec. Water breakthrough occurred after 5.5 hrs into the pump out. The overall logging from both sections was 190 operating hours, with excellent operating efficiency and high-quality data acquisition.

Fig.4. Elongated packer.

Fig.5. Extra-elongated packer.

With the sidetrack already planned, a full re-evaluation of the pressure testing and sampling techniques and equipment was based on learnings from the main bore. After having all the data from the main bore, extensive simulation work was performed to evaluate the possibility of using the new, large, flow-area packer that was designed for use on a concentric flowing formation tester. The new, large flow packer, enables the formation tester to pump faster and concentrically in low-mobility formations, where previously the standard concentric packer (**Fig. 6**) would struggle to maintain a concentric flow.

Fig.6. STD and XR Concentric Flow Packers.

The simulation was conducted with an in-house near-wellbore numerical simulator based on a black oil reservoir simulator (Liu et al, 2004), which had been used for pre-job planning of single probe fluid sampling (McCalmont et al, 2005). The simulator was used to first history match the response from the main bore and extension, and then used for concentric-focused fluid sampling (Wu et al, 2013). Concentric-probe sampling is particularly difficult in low-mobility rock because of the low pump rates and high differentials that are seen on the inner and outer lines. The problem on the main bore was the pump speed was restricted because of the differential limit on the standard probe/elongated packer and the pump capability. The modelling showed that the large flow area concentric packer would be able to maintain an 8:1 ratio in the 2mD and 5mD rock. The modelling was conducted for formation oil and OBM properties (**Fig. 7),** which showed substantial reduction in pumping time, and results in a cleaner sample obtained in a much quicker time.

The modelling results showed that the best pump configuration for the formation tester was the 434cc - 434cc, both of which have a working differential of 5,200psi. The pump speed could be maintained at 1cc/s on the sample line and 8.2cc/s on the perimeter line. A conventional probe was run with an extra elongated packer. The large-area-flow concentric packer was run on the focused fluid formation tester with two 434cc pumps and only one fluid analyser on the sample line because of weight constraints which were modelled in the Deployment Risk Management (DRM) system. The 434cc pumps, pump the maximum differential drawdown that is necessary to overcome the high overbalance and potential low mobility, and high drawdown expectancy.

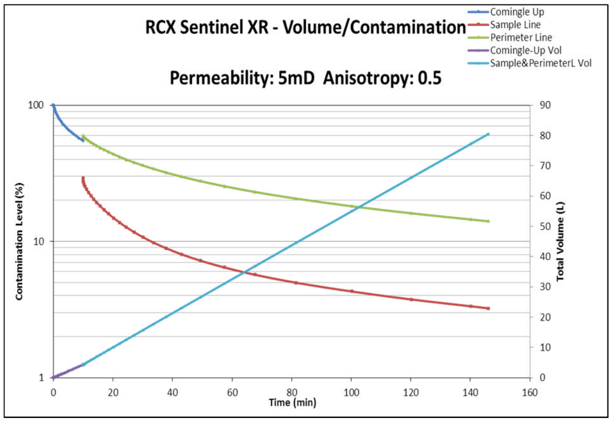

Fig.7. Volume and contamination plot for the simulation work done for the XR packer.

The tension modelling used to determine the optimum deployment strategy was performed using Baker Hughes proprietary Cerberus software prior to the job. To optimize the maximum available overpull in a stuck tool scenario, the Baker Hughes powered capstan system should be utilized in combination with a 0.490 in extra-high-strength cable. To further minimize deployment risk, wireline jars and multi-axial rotating flywheels were run in the tool string as well as using motorised releaseable cablehead (MRCH) to maximize the mechanical weak point. The unique derrick-mounted positioning of the powered capstan ensured the highest tensions only pulled vertically over the well and not across the deck. This not only reduces risk to personnel, but also the potential for drum crush and damage to the wireline.

The sidetrack was drilled with 1.5g/cc OBM and reached a depth of XX58 m. To evaluate the formation properties, acoustic and resistivity imaging, petrophysical and acoustic logs, nuclear magnetic resonance and elemental spectroscopy logs, and vertical seismic profile were logged prior to the formation testing and sampling run.

The formation tester was equipped with twelve sampling tanks and pressure testing was conducted with the conventional probe dressed with an extra-elongated packer, (**Fig.5**). The packer has an 8x flow area of a conventional probe/packer and has a differential pressure of 10kpsi. Forty-four pressure stations were conducted with eleven good tests, eleven tight tests, one supercharged test, three aborted tests, eleven are building and seven have no seals for a total of forty seven pressure tests conducted. The mobility range was between 0.3 and 3 mD/cP. Therefore, it is a very challenging environment to acquire accurate, repeatable pressures and a sample in a fast operational time period. Upon moving to the first sampling the point, challenging hole conditions were experienced where upon the DRM program outlined earlier became a critical component of the operation. Deployment risk analysis planning and technologies used included MRCH, jars, flywheels and extra-high-strength cables that enabled the successful conveyance of tool string which ultimately avoided a costly fishing operation for the client.

Using the derrick-mounted-powered capstan and running a high-rated mechanical weak point in the MRCH, the crew were able to maximize the overpull, working to the maximum safety limit of the extra-high-strength logging cable. By progressively increasing the running speed on the powered capstan up to the maximum safe working load, it was possible to move the tool string. The tools were pulled up to the CSG, however power was lost, which resulted in POOH to change the string over and perform a wiper trip through the section. Back on the surface it was determined that the wireline jars had fired, which helped move the tool string.

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After the wiper trip, the same configuration was run back in-hole to the first sample point. The mobility was approximately 0.6mD/cP from the initial pressure test with the XR packer. To initialize the sampling procedure, it is important to verify the seal integrity of the inner and outer seal on the packer. After the seal integrity is verified, a pumpout was performed with a commingled flow to check the maximum flow from both inlets. Afterward, a pumpout was performed in the down direction to establish the maximum flow capability on the perimeter only. When the seal and flow capacity was finished, a commingle pump-up sequence began and the tool pumped out 5.2 litres (**Fig. 8 and 9**). The first water slugs appeared in the commingle flow period at approximately 6,000 secs. The commingle pump speed was brought up to approximately 1.2cc/sec after which split flow was commenced at approximately 8,500 secs. A flow rate of 0.28 to 0.32 cc/sec was established through the sample line and a rate of approximately 1.13 cc/sec was observed through the perimeter line (**Fig. 10**). When the rates stabilized, the available sensors in the fluid analyser were used to establish the dominant formation fluid.

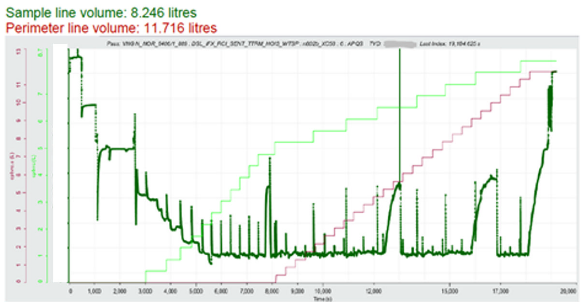

Fig.8. Pressure and volume plot.

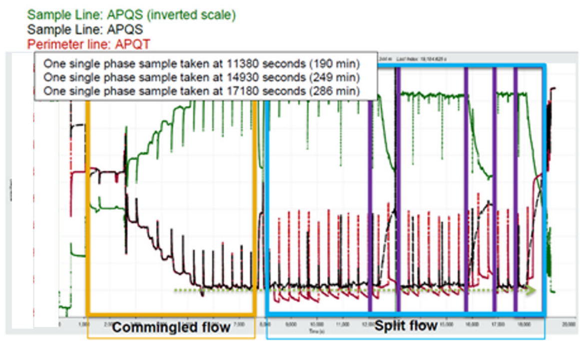

Fig.9. Commingle and split flow periods and tank filling periods (purple lines).

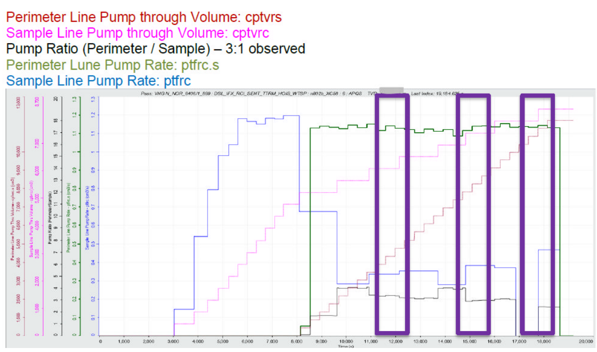

Fig.10. Rate and ratio plot, ~3:1 ratio achieved.

One problem of pumping so slowly on the sample line is that the optical density response can look rather dirty and unclear. The optical density showed that the formation fluid was water; however, the signal was noisy (**Fig. 11 and 12**).

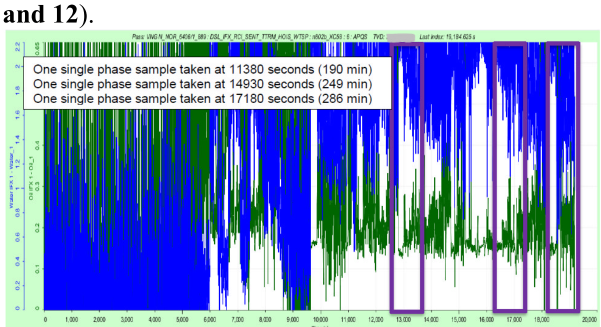

Fig.11. Oil/water optical density vs time plot.

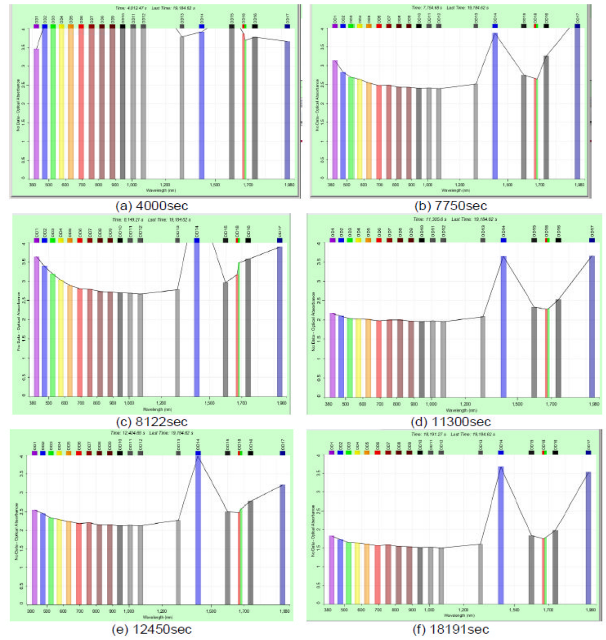

Fig.12. Spectrum plot change over time, highlighting water peaks (blue ch. 14 and 17) on the fluid analyser.

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The density measurement was very choppy because of the two-phase flow **(Fig. 13),** so the best measurement available to indicate constant water flow was the Sound Speed measurement, (DiFoggio, 2006). The Sound Speed measurement indicated a constant slowness of 188 to 189 us/ft, which gave good assurance that a low contamination sample was achievable (**Fig. 14**).

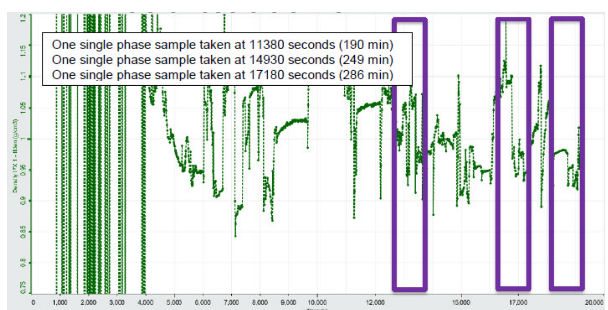

Fig.13. Tuning fork density vs time plot.

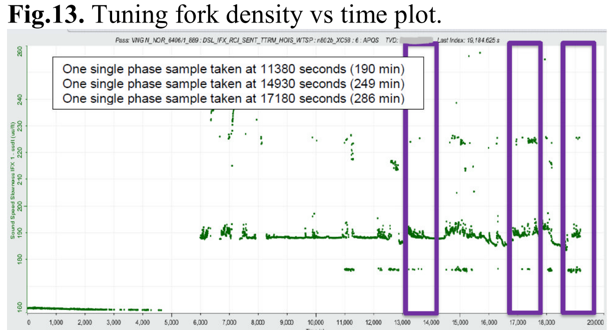

Fig.14 .Sound Speed measurement vs time plot.

When the sound speed measurement was stabilized the decision was made to fill three single phase sample tanks. The tanks were nitrogen-charged with a volume estimated at approximately 400 cc per bottle. The filling time was fairly long because of the slow pumping speed on the sample line. After the tanks were filled, the pump over-pressurized the samples and the tanks were hydraulically shut in on the tank carrier. The PVT analysis and contamination estimates were carried out on the samples and the results showed contamination as low as 2%. The results, in comparison to the main bore, where the contamination was upwards of 95%, showed the effectiveness of the concentric probe to acquire quality samples in this type of environment.

CONCLUSION

Formation testing and sampling in low-mobility formations using conventional packers and pump-out techniques can result in poor data collection and quality as well as highly contaminated samples. The use of larger flow, concentrically formed packers can substantially lower the time needed to observe the formation fluid breakthrough, thus giving confidence to the openhole evaluation and improving the sample purity. With the correct pre-job planning, and not just on the deployment side, the concentric flow XR packer enables the flexibility to acquire samples in relatively low mobility and still work in higher mobilities effectively. The flexibility to contain the “correct equipment” in-hole when expectations are different from the actual results gives the operation a wider range of properties to work within, and thus, better data collection and analysis can be performed at a significantly lower cost.

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