Reservoir Fluid Characterization with a New-Generation Downhole Fluid Analysis Tool

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ABSTRACT

This paper reports a new-generation wireline formation testing tool that quantitatively characterizes reservoir fluid. The tool measures: 1) fluid composition (C1, C2, C3–C5, C6+, and CO2); gas/oil ratio (GOR) and water fraction by VIS-NIR spectroscopy; 2) color, fluorescence, and reflectance; 3) pH if fluid is water; 4) density by a vibrating sensor; 5) flowline pressure and temperature; and 6) water salinity by resistivity measurement.

The first half of the paper presents a schematic description of the tool and explains the spectrometer accuracy improvement over existing commercial offerings. A grating spectrometer is the standard technology used for laboratory spectroscopy, and it was implemented for the first time for this downhole tool. The grating spectrometer has several advantages over existing commercial products for: 1) being able to measure semi-continuous spectrum in critical hydrocarbon peak region and 2) better signal baseline stability critical for accurate spectroscopy. More than 45 field test jobs were performed in the field test campaign. The comparisons made are between measurements performed by a new wireline downhole fluid analysis (DFA) tool and PVT analysis performed in wellsites and laboratories.

The second half of the paper discusses a deepwater appraisal well case example from offshore Nigeria, West Africa. The objective of the formation testing program was to assess the hydrocarbon potential, evaluate the fluid properties and contacts, and determine the presence of any compositional grading with depth across the reservoir section. An advanced wireline formation testing tool equipped with focused sampling and conventional probes and four downhole fluid analyzers including the new-generation tool were used. Pressure pretests were performed in this appraisal well in combination with fluid scanning and fluid sampling at seven depths across the reservoir. The combination of fluid scanning across the main reservoir and real-time measurements of in-situ fluid density also enabled the operator to rapidly assess the fluid composition and locations of fluid contacts during progression of the logging operations. The application of this new sampling and downhole fluid analysis technology provided valuable information to the operator for design of the subsequent drillstem test and results comparison.

INTRODUCTION

Downhole fluid analysis, which started as a means to assure quality fluid sampling for wireline formation testing more than 10 years ago, has evolved into a key technique for characterizing distribution of reservoir fluid properties and determining zonal connectivity across the reservoir. Primarily using visible-to-near-infrared (VIS/NIR) spectroscopic measurements, reflection measurements, and fluorescence measurements, DFA tools have offered increased capabilities over the years: oil/gas/water detection (Smits et al., 1995); oil-based mud (OBM) filtrate contamination quantification (Mullins et al., 2000); gas-to-oil ratio (Mullins et al., 2001; Dong et al., 2006); composition (C1, C2-C5, C6+, and CO2) (Fujisawa et al., 2003); fluorescence measurement (Betancourt et al., 2003); and pH measurement (Raghuraman et al., 2005).

A recent paper (Dong et al., 2007) showed the latest development of the new-generation DFA tool, including the theory of interpretations and test results in both laboratory and fields. This new article mainly covers hardware features and a summary of more than 45 field test jobs from all over the world. This article also gives a somewhat more detailed description of a deepwater appraisal well case from offshore Nigeria, West Africa.
A NEW-GENERATION DFA TOOL

The new-generation wireline formation testing tool has the capability to measure: 1) fluid composition (C1, C2, C3–C5, C6+, and CO₂); gas/oil ratio (GOR), and water fraction by VIS-NIR spectroscopy; 2) color, fluorescence, and reflectance; 3) pH if fluid is water; 4) density by a vibrating sensor; 5) flowline pressure and temperature; and 6) water salinity by resistivity measurement. Fig. 1 shows the schematic drawing of this new wireline tool.

This paper focuses on improvement made on spectroscopic measurement over existing commercial products. This new wireline tool has two spectrometers: 1) grating (GR) spectrometer for covering hydrocarbon peak region and 2) filter array (FA) spectrometer for covering wider spectral coverage (Fig. 2). Readers interested in other measurements of this tool can find more information on water pH measurement by pH dye injection and spectrometer (Raghuraman et al., 2005), and density measurement by a vibrating sensor (O’Keefe et al., 2007).

The single most important factor for DFA today is accurate measurement of downhole fluid spectra. The reliability and accuracy of composition analysis and GOR determination totally depends on it. There are several factors that constitute spectrometer accuracy: i.e., signal baseline stability, signal dynamic range, signal resolution, wavelength stability, wavelength coverage range, and wavelength resolution. Among these factors, signal baseline stability and wavelength stability most influence measurement accuracy. These are discussed below.

Signal baseline stability
One of the biggest challenges for designing a spectrometer for downhole use is stability of the spectrometer baseline under the harsh environments typical of oil wellbores. Generally, a spectrometer has two optical paths: one for investigating a sample (sample path) and the other for monitoring fluctuation of light source (reference path). A spectrometer baseline is established by measuring the ratio of light signal intensities at the sample path over the reference path at a given reference condition, which is typically an empty cell (i.e., dry air). Absorption spectrum is defined relative to this reference baseline and thus it is critical for the baseline to remain stable from the time it was established on surface to the points when and where actual sample measurement takes place, which is in a high-temperature borehole environment. In addition, the spectrometer can experience a substantial amount of shock and vibration, so the DFA spectrometers were designed to achieve good baseline stability.

Wavelength accuracy and stability
The accuracy and stability of wavelength is another important factor for the DFA spectrometer. Similar to the case for the signal baseline stability, the wavelength must remain stable under high wellbore temperature and/or shock and vibration. Otherwise, a drift of wavelength will translate into an optical density (OD) error that propagates to fluid composition and GOR uncertainties. Fig. 3 shows transmittance of a bandpass filter at room temperature and at 210 degC as an example. It shows an excellent stability with a shift much less than 1 nm.
Fig. 3. Transmittance of optical filter remains almost invariant up to 210 degC, guaranteeing wavelength accuracy and stability at wellbore temperature.

The new-generation DFA tool has two different spectrometers as depicted in Fig. 1, and they have following strengths.

A grating (GR) spectrometer is the standard technology used for laboratory spectroscopy, and it has been implemented for the first time for downhole tool. The GR spectrometer has several advantages over existing commercial products: 1) it can measure semi-continuous spectrum in the critical hydrocarbon peak region (Fig. 2) and 2) it has better baseline stability, which is critical for accurate spectroscopy. Normalized by a reference wavelength, the signal baseline stability of OD of 0.005 rms has been achieved for the GR spectrometer in our test facility against the combined effects of temperature, shock, and vibration on wireline tool operation. The accuracy and stability of the wavelength is +/- 1 nm.

A 20-channel filter array (FA) spectrometer covers a wider spectrum range. Several improvements made the new FA spectrometer more accurate compared to the existing commercial DFA tool FA spectrometers. The advantage of the FA spectrometer is wider wavelength coverage (visible to near-infrared) and dynamic range (OD3 or better). In addition to hydrocarbon peak spectrum measurement, it covers water peak, oil color, pH dye peaks, and CO2 peaks (Fig. 2). For the FA spectrometer, the signal baseline stability has OD of 0.01 rms against the combined effects of temperature, shock, and vibration on wireline tool operation. The accuracy and stability of wavelength is +/- 1 nm.

A new interpretation algorithm was developed for this new tool (Dong et al., 2007), and it takes the strengths of each spectrometer into account to determine the fluid composition and GOR.

Comparisons between in-situ DFA measurements and wellsite/laboratory analysis are given for composition (Fig. 4) and GOR (Fig. 5), from the field test database. The agreements are good. Some caution is needed to interpret the results in these figures because wellsite/laboratory analyses do not necessarily give ground truth. The wellsite/laboratory analyses are only as good as the fluid samples delivered to the wellsite/laboratory, where DFA measures sample fluids at almost reservoir pressure and temperature conditions. Also, any mishandling of captured samples invalidates comparisons to DFA measurement results. Looking at the details of Figs. 4 and 5 with this understanding, they show better agreement between DFA results and laboratory analysis results (solid markers), compared to matching between DFA results and wellsite analysis (hollow markers).
A CASE EXAMPLE

This field example in the Gulf of Guinea, offshore West Africa, is from a deepwater vertical appraisal well, which was drilled with OBM. The water depth is approximately 1,000 m, and the main reservoir intervals are within a Pliocene-age sedimentary channel complex between XX00 and XX90 m TVD. The objective of the formation testing program was to assess the hydrocarbon potential, evaluate the fluid properties and contacts, and determine the presence of any compositional grading with depth across the reservoir section. An advanced wireline formation testing tool equipped with focused sampling and conventional probes and four DFA modules including two in-situ density sensors was used. The first density sensor was deployed in the focused probe module, and the second density sensor was integrated in the new-generation fluid analyzer tool. In this example, three DFA modules that include the new-generation tool are placed in the sample line of the focused sampling probe, and one DFA module is placed in the guard line.

Fifty-six pressure pretests were performed in this appraisal well, in combination with fluid scanning and sampling at seven depths across the reservoir. Three stations were performed in the gas-bearing interval, three stations in the oil zone, and one in the water zone. Fig. 6 displays the pressure pretest data and interpreted fluid gradients alongside the openhole logs and compositional measurements from a downhole fluid analyzer tool. For the sake of brevity, we will examine two sampling stations within the oil zone at XX54.5 m and XX88.5 m. We compare the measured in-situ fluid density values with the optical spectrometer data and results from both pressure gradient analysis and fluid sample wellsite PVT results.

**Fig. 5.** Comparisons of DFA results against wellsite analysis (hollow markers) and laboratory analysis (solid markers) for fluid GOR.

**Fig. 6.** The log showing (from left to right) pressure gradient, density measurement by density sensor, fluid composition by a new DFA module, gamma ray log, drawdown mobility, and petrophysical analysis.
The quality of the pressure and optical fluid analyzer data displayed in Fig. 6 is good. Three pressure gradients corresponding to gas, oil, and water can be identified (straight-line fits were assumed), all in pressure communication. In the main oil intervals between depths XX45.9 m and XX95 m, a linear pressure gradient can be fitted with an oil density of 0.71 g/cm$^3$ (0.307 psi/ft) and an $R^2$ of 0.9985. The fluid gradient within the oil-bearing intervals appears to be a straight line with no obvious indicators of vertical pressure compartmentalization or compositional grading. For comparison, the wireline formation tester in-situ fluid density measurements are plotted in red circles versus depth alongside the pressure pretests and the interpreted fluid gradients. Table 1 summarizes the in-situ fluid density values from the wireline formation tester sensor for each station and compares them with values from pressure gradient analysis and wellsite PVT results. The first density sensor is located within the focused sampling probe and hence measures under flowing pressure, while the second density sensor is integrated into the fluid analyzer module and measures close to hydrostatic pressure. In each case the density values are consistent and comparable to values indirectly determined by pressure gradient analysis and values measured from wellsite analysis of PVT samples.

**Table 1.** Comparison of density values from pressure gradient, density sensors, and wellsite analysis.

<table>
<thead>
<tr>
<th>Depth (m)</th>
<th>Pressure gradient (g/cm$^3$)</th>
<th>Density Sensor 1 at probe (g/cm$^3$)</th>
<th>Density Sensor 2 at DFA (g/cm$^3$)*</th>
<th>Wellsite analysis (g/cm$^3$)*</th>
</tr>
</thead>
<tbody>
<tr>
<td>XX54.5</td>
<td>0.71</td>
<td>0.688</td>
<td>0.713*</td>
<td>0.699</td>
</tr>
<tr>
<td>XX69.5</td>
<td>0.71</td>
<td>0.675</td>
<td>0.711*</td>
<td>N/A</td>
</tr>
<tr>
<td>XX88.5</td>
<td>0.71</td>
<td>0.694</td>
<td>0.709*</td>
<td>0.691</td>
</tr>
</tbody>
</table>

*Density Sensor 2 at DFA module measures fluid density under hydrostatic pressure, which is higher than reservoir pressure, and thus its reading is higher than other fluid density measurements at reservoir pressure.

Table 2. Compositions and GOR measured by three DFA tools and wellsite analysis for fluid at XX54.5 m.

<table>
<thead>
<tr>
<th>New DFA tool</th>
<th>DFA Tool A</th>
<th>DFA Tool B</th>
<th>Wellsite</th>
</tr>
</thead>
<tbody>
<tr>
<td>C1 (wt%)</td>
<td>9.3</td>
<td>N/A</td>
<td>9.2</td>
</tr>
<tr>
<td>C2 (wt%)</td>
<td>3.0</td>
<td>N/A</td>
<td>9.1 for C2-C5</td>
</tr>
<tr>
<td>C3-C5 (wt%)</td>
<td>6.8</td>
<td>N/A</td>
<td>3.7</td>
</tr>
<tr>
<td>C6+ (wt%)</td>
<td>80.9</td>
<td>N/A</td>
<td>81.7</td>
</tr>
<tr>
<td>CO$_2$ (wt%)</td>
<td>0</td>
<td>N/A</td>
<td>0</td>
</tr>
<tr>
<td>GOR (scf/bbl)</td>
<td>1,129</td>
<td>1,080</td>
<td>980</td>
</tr>
</tbody>
</table>

A brief description of two of these examples follows.

**Station A at XX54.5 m**

Station A was at XX54.5 m near the top of the oil-bearing zone of the reservoir. Compositional information from the new DFA tool is presented in Fig. 7.

During early time in the pumping out prior to sampling, the new DFA tool composition shows minor fluctuation as in Fig. 7. It is caused by the minor optical density fluctuations of all the channels synchronized with pump strokes, and they are related to residual OBM filtrate contamination in the pump displacement unit. The fluid composition and GOR are measured in-situ by the three DFA tools in the sample line and later by wellsite analysis performed on the captured sample (Table 2). It is interesting to observe the difference in these results. Roughly speaking, the three DFA results agree among themselves; however, the wellsite analysis is somewhat different. Considering that the observed difference is larger than the measurement uncertainty of the new DFA tool, it seems the fluid might be different between downhole conditions and the surface, where the wellsite analysis took place (i.e., the sample integrity is questionable).
The composition and fluid density measurements indicate a medium black oil. The density values from the two density sensors are compared to results from wellsite PVT analysis of captured fluid samples in Table 1. At around 9,000 seconds elapsed time, the values between each density sensor differ by approximately 0.025 g/cm³, primarily due to the different pressure regimes within the toolstring flowline. Wellsite PVT analysis of fluid samples yields an oil density of 0.699 g/cm³ at reservoir conditions (2,980 psia and 85.8 degC).

Station B at XX88.5 m
Station B at XX88.5 m was also performed within the oil zone of this reservoir (Fig. 6). Fig. 8 presents the real-time compositional measurements from the new DFA tool.

![Graph](image)

**Fig. 8. Composition from the new DFA tool.**

Data quality is good, with density values from the sensors in the focused probe and fluid analyzer modules reading 0.694 g/cm³ and 0.709 g/cm³ respectively (Table 1). Wellsite PVT analysis of fluid samples captured during these sampling operations provide an oil density of 0.691 g/cm³ at reservoir conditions (3,013 psia and 88.1 degC), matching within 0.003 g/cm³ to the in-situ density from the focused probe module measured at sandface pressure. The fluid composition and GOR are measured in-situ by three DFA tools and later by wellsite analysis performed on the captured sample (Table 3). A similar trend is observed for the variations among DFA analysis and wellsite analysis.

| Table 3. Comparison of compositions and GOR by DFA tools and wellsite analysis for fluid at XX88.5 m. |
|-------------|----------------|----------------|----------------|----------------|
|             | New DFA tool  | DFA Tool A     | DFA Tool B     | Wellsite       |
| C1 (wt%)    | 9.5           | N/A            | 10.35          | 7.4            |
| C2 (wt%)    | 3.1           | N/A            | 9.0 for C2–C5  | 1.1            |
| C3–C5 (wt%) | 7.4           | N/A            | 80.7           | 3.9            |
| C6+ (wt%)   | 80            | N/A            | 80.7           | 87.4           |
| CO₂ (wt%)   | 0             | N/A            | 0              | 0.2            |
| GOR (scf/bbl) | 1,180       | 1,207          | 1,075          | 723            |

Interestingly, all four analyses (three DFA analyses and one wellsite analysis) results indicate the fluid GOR is higher at XX88.5 m compared to the fluid situated at the shallower depth at XX54.5 m. Density measurements by density sensor and wellsite analysis also confirm the same trend (Table 1). These measurement results indicate the oil at XX88.5 m is slightly lighter and contains more dissolved gas compared to the oil at the shallower depth of XX54.4 m. OBM contamination in the captured samples are 4.9% for XX88.5 m and 3.2% for XX54.5 m, and the contamination alone cannot explain this observed trend. It indicates the possibility that the oil zone may not be at equilibrium, which could be due to poor vertical fluid communication regardless of apparent pressure communication. The GR log and petrophysical analysis result shows potential permeability barriers slightly below XX60 m.

For this field case, the combination of in-situ downhole fluid scanning and measurement of fluid density across the main reservoir intervals in real time, enabled the operator to rapidly assess the fluid composition and locations of fluid contacts during progression of the logging operations, and to acquire valuable information for input and comparison with a planned drillstem test. This example also shows the practical application of DFA scanning at multiple depths to reveal fluid compositional information, and its variation with depth at a much higher resolution than conventional sampling and previous generation fluid analyzers allowed. This means that fluid variations with depth can now be accurately quantified for an enhanced understanding, and can acquire information for input and comparison with early fluid and reservoir simulation models.
SUMMARY

This article discusses a new-generation DFA tool and its application. It explains the hardware improvements made on spectroscopic measurements that are critical to accurate fluid composition and GOR analysis. The prototype tools have been extensively tested in diverse environments all over the world, totaling more than 45 field tests. Agreements between DFA results and wells/laboratory analysis are good for both composition and GOR. This article gives a detailed description of a deepwater appraisal well case from offshore Nigeria, West Africa. The combination of in situ downhole fluid scanning and measurement of fluid density across the main reservoir intervals in real time, enabled the operator to rapidly assess the reservoir in this job.

REFERENCES


