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Applications of Wireline Formation Testing (WFT) and Downhole Fluid Analysis (DFA): Reviewing the Importance of This Technology in Reservoir Evaluation

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Abstract

Wireline formation testing (WFT) is an important aspect in both exploration and production phases for reservoir evaluation. WFT tools can directly measure the formation pore pressures and then the pressure profiles are used to identify; the type of pore fluids, the fluid's density, fluid contact, depletion and overpressure, and continuity and connectivity of the reservoir in both the lateral and vertical directions. WFT is mostly used to evaluate formation permeability and taking fluid sampling.

The new generation wire-line formation sampling tools includes a downhole fluid analyzer (DFA), which can analyze the composition of fluids in real-time and under in-situ conditions and also can measure the spectra of crude oil. So, in result, it is possible to identify fluid compositional variations and reservoir vertical compartmentalization. The analysis of fluid composition depends on the optical absorption, and the mass fraction estimation for the three groups of hydrocarbons: methane (C_1), $C_{2\text{-}5}$, and C_6 + along with CO_2 as well. Also, it provides formation fluid properties like gas oil ratio (GOR), density, viscosity, and resistivity. The DFA results are subsequently validated and modified by laboratory analysis on the fluid samples attained from the formation.

The potential advantage of early measurements demonstrates that the DFA is a good decision-making solution in early stage without waiting for the lab result for months. Also, early DFA measurements are important in well completion and well testing designing, the establishment of fluid gradients in reservoirs, reservoirs connectivity, identifying and validating fluid distributions in reservoir.

1. Introduction:

Wireline formation testing has undergone several improvements since the 1950s, particularly in the design of tools to identify fluid and estimate pressure. It consists of many modules and components that are interchangeably configurable depending on the properties of the reservoir and the job objectives [1]. It has been used to obtain formation pressure, type of fluid, fluids contact, and permeability. Pressure profiles provide precious information for developing the field and it is also very important for reservoir management to obtain a pressure profile as a reference in the reservoir before the start of the production operations [2].

However, in several situations, the information on the quality of the measured formation pressures with depth is not enough to determine the accuracy of the fluids` gradients and fluids` density. Usually,

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accurate pressure in fractured, thin-bedded or highly laminated, and vuggy formations is challenging. Supercharging with low mobility formations and mud filtrate can also affect the measurements that put it hard to get data of representative pressures and interpret the pressure gradients [3], [4]. It will be hard to analyze the pressure gradient accurately in all pre-mentioned conditions and get the correct fluid density. Also, the compartmentalization of the reservoir and the fluid composition are not identified by the analysis of the pressure gradient. So, in this case, the presence of DFA can be highly beneficial [5].

Downhole fluid analysis (DFA) is a technique that help to characterize the reservoir fluids` properties and to determine the fluid compositional gradients [6]. It is based on optical spectroscopy that can also estimate filtrate contamination [7], GOR, composition of hydrocarbons in four groups (C_1, $C_{2\text{-}5}$, C_{6+}, and CO_2).

DFA provides all measurements in real-time and under reservoir conditions [8][10] and it can be used for single-phase assurance where gas release and liquid dropout can be detected while the reservoir fluid is pumped to wellbore before filling a sample chamber. It allows downhole measurement of fluid viscosity and density at reservoir conditions [11]. The result of DFA is validated later by results of PVT laboratory analysis conducted on the representative sample [12]. DFA measurements are important in well testing, well completion, reservoirs connectivity, and reservoir fluid distributions. WFT and DFA data within a wellbore is very useful for reservoir evaluation when it is paired with the open hole log data [13]

2. Tool modules:

2.1 Single probe module:

A single probe module is designed to connect the tool with the reservoir (Fig. 1a). It contains the assembly of the probe, pretest chamber, gauges for pressure, sensors for resistivity and temperature. The assembly of the probe includes a small packer and telescopic pistons that are used to press the packer across the wall of the borehole. The probe is further pressed across mud-cake to get in contact with the formation. Communication with formation is established by a limited pretest, followed by withdrawing of fluids for sampling [14].

2.2 Multi-probe module:

The multi-probe module consists of three assemblies of different probes placed on the same mandrel in fixed positions as seen in Fig. 1b. The two probe assemblies in the tool are mounted on the mandrel diametrically in opposite direction. One of these two probes is a sink and the other is just a monitor that has no sampling possibility (also known as the horizontal probe). The dual-probe module's primary function is combining with a vertical probe to evaluate kh and kv with the help of a localized interference test [15].

2.3 Dual packer module:

The dual packer module has two straddle packers, which can isolate 1 meter of formation interval in the vertical direction (Fig. 1c). The pump-out module inflates the packers to isolate the borehole from the drilling fluid. The dual packer module can be used to carry out the mini drill stem test (DST). The interference test may be performed if the probe module is included. The probes may be ineffective and inefficient when installed in formations like fractured, unconsolidated, vuggy, laminated, and low-permeability [14]. In these conditions, pressure measurements and sampling can be done by the use of dual packers. It can isolate a larger area of the reservoir relative to the probe, which helps to get a larger flow rate and increases the investigation depth to tens of meters [16].

2.4 3D Radial probe module (Saturn):

The 3D radial probe module (Fig. 1d) has gained significant popularity as new technology. It has four sealing ports placed at 90° against the borehole wall [17]. This new design overcomes many difficulties that are faced by other modules [18]. The radial model eradicates the storage volume between the packers as in the dual packer module and allows the flow from formation directly. A much larger flow area is provided by the four ports spaced radially around the tool. This tool is appropriate to use in formation that has very low permeability and heavy fluid, where low mobility values with tight rocks and heavier fluid need more drawdown and that will lead to get sanding and plugging of the tool but with Saturn this problem can be avoided and the draw down will be low. It provides faster set, retracting time, and testing time because of large flow area is reduced, thus the sticking problems in the open hole is avoided [19]. It offers clean-up performances better as compared to the other WFT probes because of its large flow area [20].

2.5 Pump-out module:

The pump-out module is used to pump the undesirable fluid (mud filtrate) from formation to the borehole, so that, it is used to take samples. The module is used to inflate the packers by pumping from the sample chamber inside the tool [21], [22].

2.6 The Multi-sample Module:

The multi-sample module is used to collect samples of high quality. It is designed to extract six samples of the reservoir fluids, measuring 450-cc separately, with just one trip through the well. Sample bottles can be safely removed from the WFT tool to be set for the PVT lab. The sample bottles are appropriate for the transportation and the shipment of pressurized vessels [21], [22].

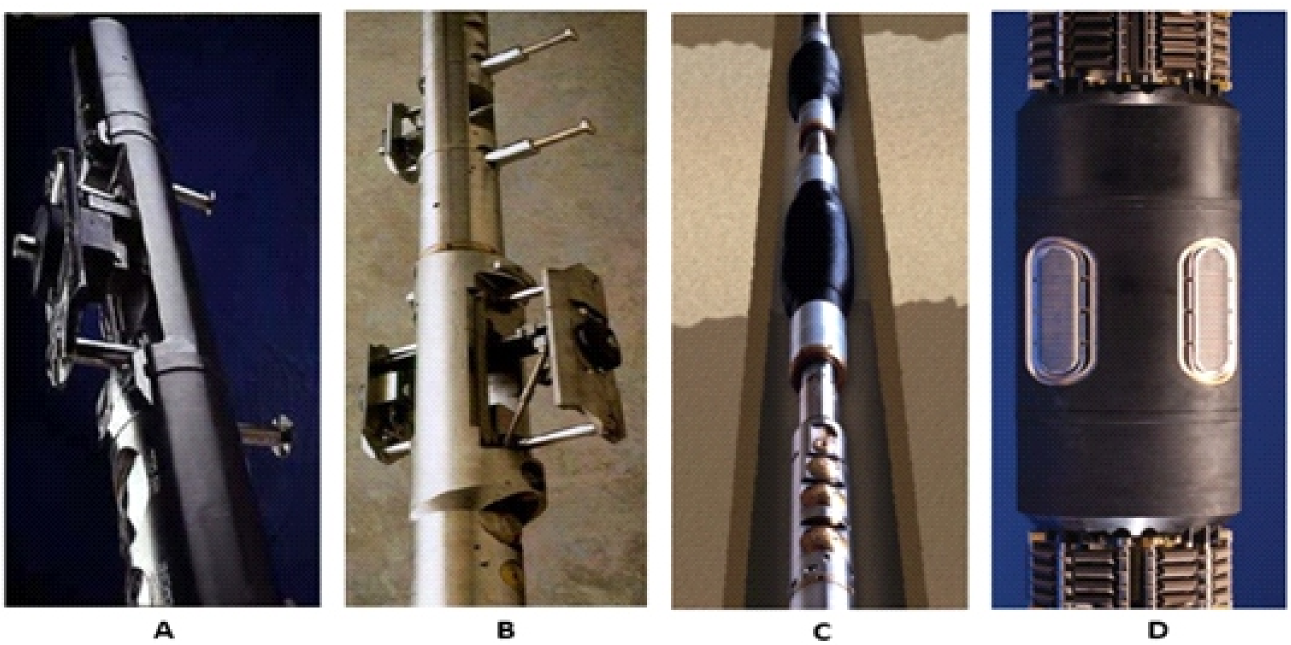


Figure 1: WFT modules (MDT), A: single probe module, B: Double probe module, C: dual packer module and D: 3D radial module, adapted from [23], [24]

3. Pressure measurement:

The typical method of measuring the reservoir pressure and calculating the formation fluid mobility is to embed a probe across the formation into the mud cake, followed by withdrawing the fluid volumes. Mobility and pressure estimation at the sandface near the probe might be achieved by evaluating the resulting drawdown and buildup in pressure [25].

The formation pressure relies on assuming that a stabilized pressure value is reached, as shown in Fig. 2. This condition may not be achieved occasionally. The situation, for instance, when the pressure buildup was curtailed before reaching its final flow regime, or the formation is very tight. In these cases, errors may occur which could significantly affect pressure gradient calculations [26].

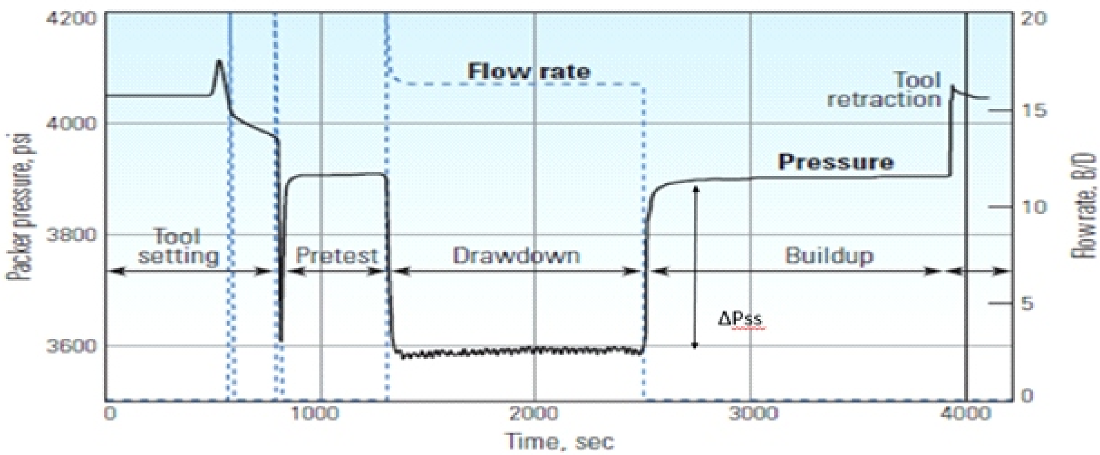


Figure 2: formation pressure measurement curve adapted from [14]

It may be difficult to get precise pressure values in vuggy, fractured, extremely laminated, or tight reservoirs, that will result various challenges in achieving the data of formation pressure. One of the most important issues for measurement of formation pressure is supercharging; which may not validate pressure measurement by WFT from a small volume (< 20 cc) [25].

3.1 Pressure Gradient Analysis

The most widely used technique for interpretation of formation pressure is the pressure versus depth plot, which showing the pressure against the vertical depth (TVD) as demonstrated in Fig. 3. In the context of formation fluid density, the pressure gradient can be interpreted. Therefore, it provides an explanation about the fluids type present; gas, oil, and water. The two-line intersection identifies the contact or the interface between different fluids in the reservoir. Graphs of pressure versus depth can be plotted for different intervals or layers in single wells and also in several wells in order to estimate the fluid contact and pressure gradients. They may be used to measure continuity in reservoir and pressure communication [25]. They are also used to assess the transition zone between two fluids [27].

Howes (2000) illustrated different situations, which can be encountered with WFT data within an individual wellbore. Some scenarios involving multi-well WFT data. The presence of overpressure, regional aquifer depletion, or hydrodynamics is certainly important while estimating hydrocarbon column thickness [28].

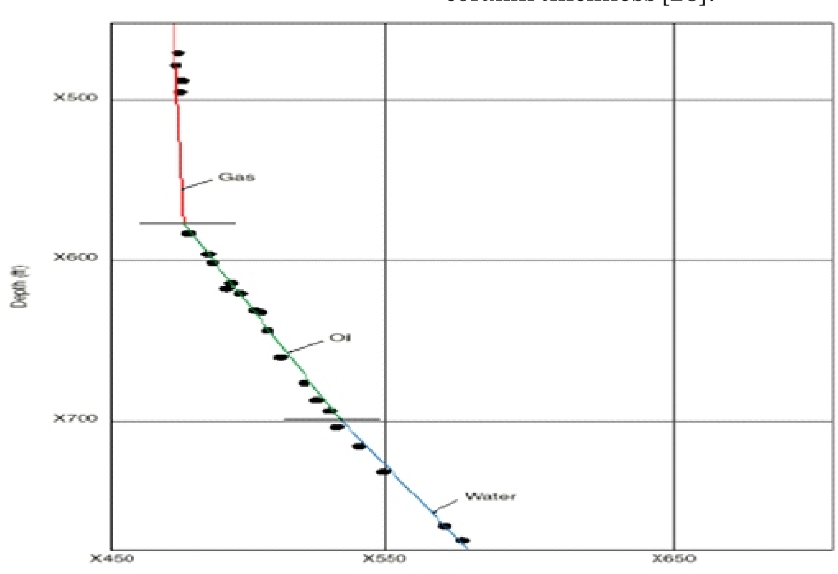


Figure 3: Depth vs pressure plot [25]

3.2 Supercharging:

With probe-type WFT tool, only mobile phase pressure can be determined on the sandface close to the probe. Wellbore fluid is injected into the formation unless the mud-cake provides an effective sealing between the sandface and wellbore. It may result in pressure considerably larger than the pressure of the formation [26]. This effect is known as Supercharging and is more likely to happen in formation of low permeability [29]. Also, supercharging occurs due to entering the mud filtrate into the formation from the wellbore during mud circulation. Because of mud filtration in the wellbore's vicinity, the formation might have pressure higher than actual formation pressure [30]. Many numerical studies are performed in order to observe the supercharging effect on pressure measurements [31], [32].

Using of the dual packer module gives the approach, which is very effective and accurate and is known for preventing supercharging. Where the formation between the two packers will be isolated from the wellbore fluid, that is at overbalance pressure [26].

4. Permeability and Mobility measurement:

4.1 Permeability measurement by single probe module:

The pretest analysis can be used to measure the mobility and the permeability from formation pressure tests. Spherical mobility is estimated from the drawdown (Fig. 3) after the assumption that a steady state inflow can be attained at drawdown. Then the spherical permeability (K_{dd}) is estimated. Thus, we have the equation [33]:

$$\frac{Kdd}{\mu} = C\ \frac{q}{\Delta Pss} \quad (1)$$

Where:

K_{dd} is permeability from drawdown analysis (spherical permeability), mD

C is WFT flow shape factor

q is the estimated flow rate of WFT (cm^3/s)

is viscosity of fluid (cp)

P_{ss} is steady state drawdown pressure drop (psi)

The spherical flow regime is controlled by an approximating spherical permeability with equation 2 below [34]:

$$K_{sp} = K_z^{1/3} K_r^{2/3} \quad (2)$$

Several reasons make Eq. 1 not more than a qualitative interpretation. The main disadvantage is the shallow depth of investigation which is restricted for invaded zone and does not indicate reservoir permeability. The other ambiguity is the fluid viscosity as the fluid in the invaded zone is difficult to be determined. But also depending on the assumption that the steady state is achieved which may not be valid [33]. The drawdown is almost limited and steady state may not be obtained. However, in order to reach pressure stabilization, the buildup time can be extended. A stabilized pressure in build-up guarantees that

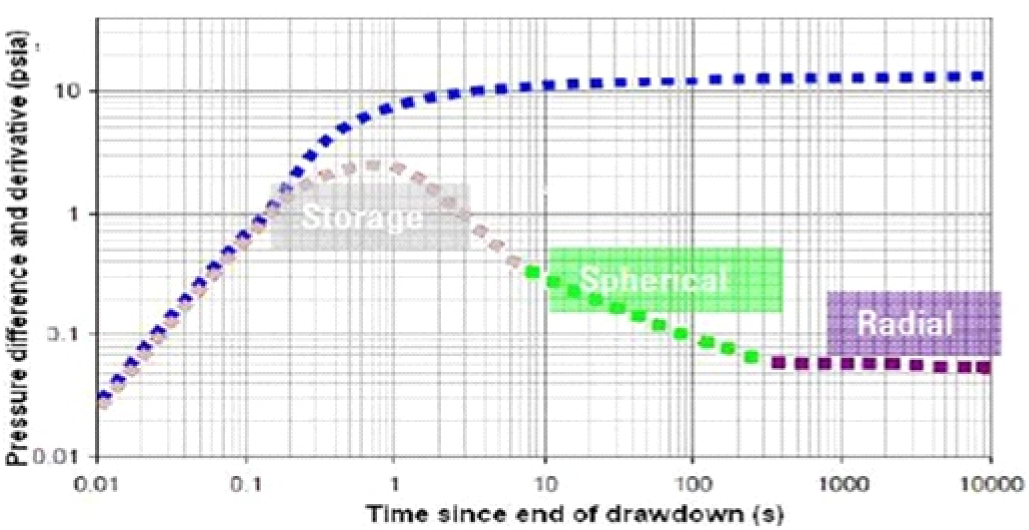


Figure 4: buildup derivative analysis for single probe module [34].

Buildup generally has a bigger investigation radius than drawdown, in the order of a meter, and it is conducted by derivative analysis to determine permeability thickness (kh) as shown in Fig. 4. However, buildup analysis for probe type is rarely used for permeability purposes because the flow regime is affected by heterogeneities surrounding the probe thus makes it difficult to determine the real contributing thickness. Also, probe-type tools do not produce a real radial flow, since pressure transient lines propagate around the wellbore [34]. Permeability from probe-type tools gives valuable information, but uncertainties arise when applying it to the whole reservoir because of the limited depth of investigation.

4.2 Permeability measurement by dual packer module

Permeability can be estimated by using a dual packer module (by carrying out mini-DST or interval pressure transit test IPTT). With IPTT, it can produce 10 to 100 liters typically, followed by a pressure buildup for 1-2 hours. These tests develop a radial flow at the reservoir scale [36], [37].

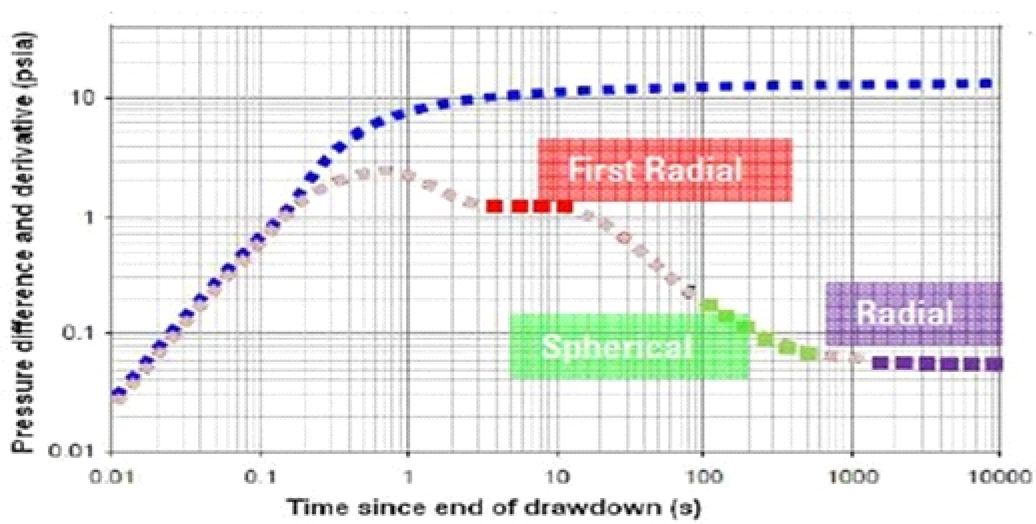


Figure 5: buildup derivative analysis for dual packer module [34].

Fig. 5 illustrates a buildup analysis of the IPTT test that done by a dual packer tool. Theoretically, a first radial flow appears after storage, which corresponds to the horizontal permeability thickness of the straddled interval. Practically this is seldom observed since it is masked by storage effects. Aspherical flow regime develops if the reservoir boundaries are thicker than the straddled interval. Then comes the radial flow, which corresponds to the permeability thickness of the whole reservoir in between the impermeable boundaries. Consequently, anisotropy permeability ratio kv/kh can be determined by observing the spherical flow regime. If the radial flow is then observed, the values of kv and kh can be determined [34].

5. Downhole fluid analysis:

DFA measurements are conducted with the help of a modular wireline formation sampling tool. Measurements are performed at reservoir conditions and in real-time [6]. DFA techniques are used in order to identify reservoir compartmentalization and connectivity together with fluid heterogeneity. Engineers use DFA to analyze the fluid properties used for effective reservoir development [23]. The properties of fluids result from several sensors. This is indeed important for DFA hydrocarbon measurement. The technique uses the properties of light absorption and light scattering of other materials to determine the following measurements [38]:

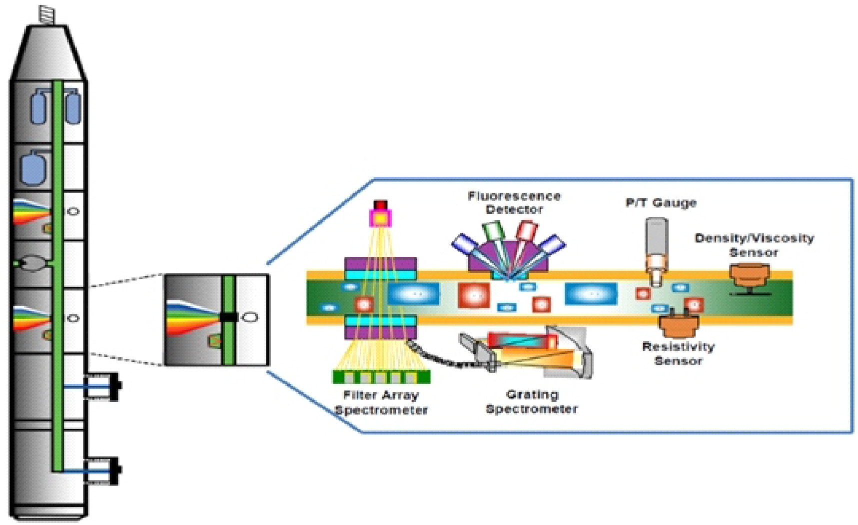


Figure 6: Downhole fluid analyzer schematic, adapted from [39]

1. Fluid composition (C_1, C_{2-5} and C_{6+})
2. Gas/oil ratio
3. CO_2 concentration
4. Color
5. Fluorescence
6. Viscosity and live fluid density
7. Contamination by oil-base mud [40]
8. Resistivity
9. Temperature and pressure

5.1 Main components:

The new DFA tool in Fig. 6 consists of several sensors as demonstrated below:

5.1.1 Two spectrometers - Grating (GR) and Filter array (FA):

They use the same optical cell but have different ranges of wavelengths and give a complementary function for one to the other. The 20 channel wavelengths within the FA vary from 400 to 2,100 nm. Such channels demonstrate the absorption of reservoir fluid by color and molecular vibration, as well as display the major peaks in water and CO_2 absorption. The GR comprises 16 channels that focus on the 1,600 to 1,800 nm range with the typical absorption of the reservoir fluid specifying its molecular structures [6], [11]. The lines in the graph below "FA" and "GR" represent the ranges of wavelength for the two spectrometers. The channels of FA and GR are designed to identify and study the components of hydrocarbons and CO_2 in natural gas and oil, to measure the PH, and water content [41].

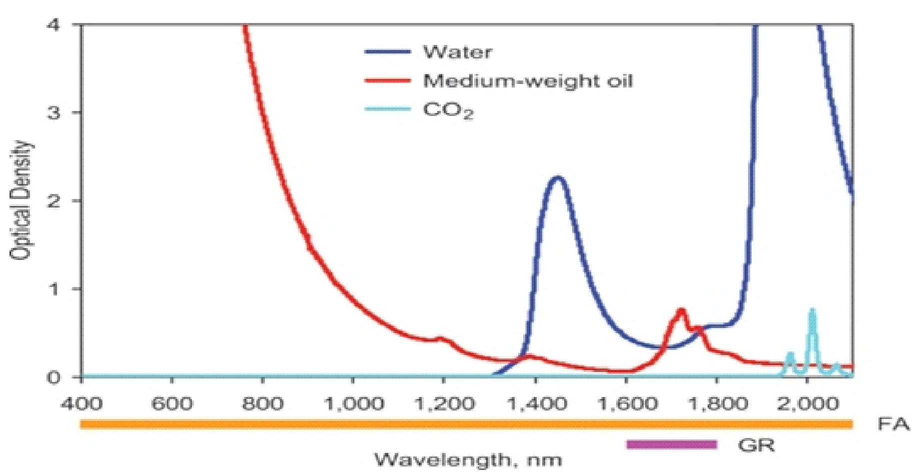


Figure 7: Spectra for oil, water, and Co_2 and different wavelength of FA and GR spectrometer [11]

5.1.2 The fluorescence sensor:

The instrument consists of three major measuring channels, the two are for fluorescence and one is for reflection. The fluorescence sensor's key roles are to recognize gas bubbles, liquid drop-out and detect the type of fluid for monophasic assurance.

5.1.3 The density and viscosity sensors:

Measurements of viscosity and density depend on the vibrating sensor's resonance features, which oscillate within a fluid in two perpendicular modes. The physical model was created that precisely define the sensor's resonance frequency and quality factor concerning fluid viscosity and density [6], [11]. Fluid viscosity and density measurement procedures are defined in more detail by Khalil et al. and O'Keefe et al. [42], [43].

5.1.4 The resistivity and P/T sensors:

The traditional sensors which are currently utilized in the WFT tool are resistivity and P/T sensors. These sensors deliver extra information and control the DFA using a newly introduced fluid analyzer. Direct pressures and temperature measurements are important to indicate the locations on the PVT envelope, and also the resistivity is measured particularly if the sensors are positioned at the downstream of the flow line pump [6], [11].

5.2 Optical properties of formation fluid:

The transmittance of reservoir fluids due to wavelength may differ over a broad dynamic scale, and sometimes on a logarithmic scale, it is beneficial to demonstrate optical properties. The optical density (D) is therefore described by the given formula:

$$D = \log (1/T) \tag{3}$$

Fig. 8 displays the spectra absorption as optical density. The properties of these absorption spectra are mainly responsible for three phenomena: molecular vibrational absorption, electrical absorption, and scattering.

5.2.1 Molecular Vibrational Absorption:

In the near-infrared water has two characteristic peaks of absorption: one at 1450 nm and a stronger one at around 2000 nm. These wavelengths have natural resonance correspondence with O-H bonds and thus they absorb photons with those wavelengths. Fig. 8 illustrates various oils having an absorption peak approximately at around 1700 nm. The absorption outcomes from the resonance of C-H bond comparative with the resonance of O-H bond [44].

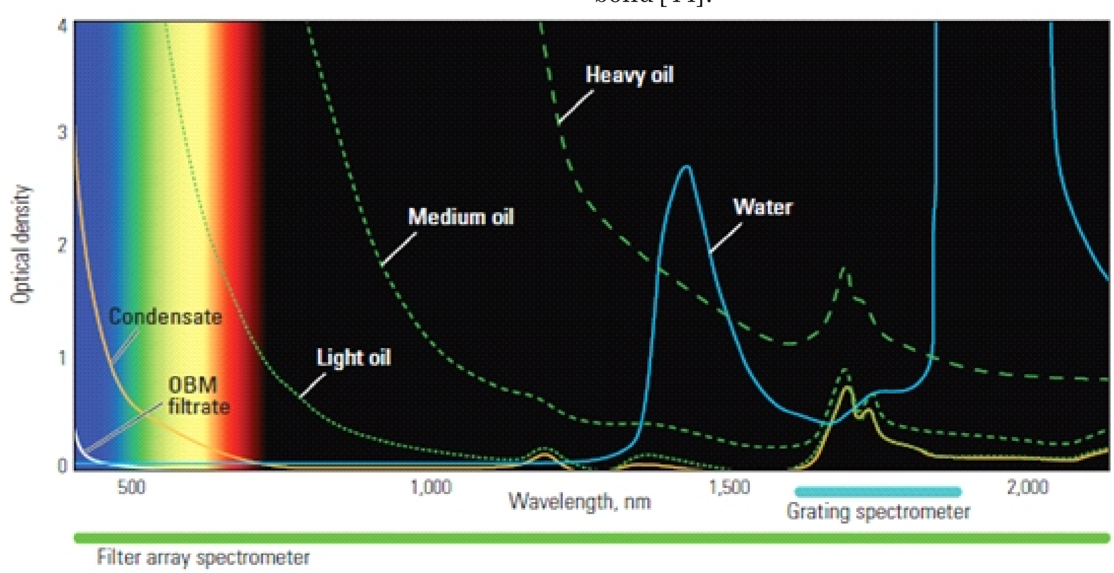


Figure 8: A spectra absorption for hydrocarbons [8]

5.2.2 Electrical Absorption (Color)

The presence of color is an additional significant feature of such absorption spectra, which predominates the smaller wavelength portion of spectra as illustrated in Fig. 8. Pure light hydrocarbons are basically colorless just like the water. Nevertheless, condensates may look like transparent or very light reddish-yellow, although other crudes may appear like black or dark brown color; fuel oils and diesel transform to dark brown to white color. Such like colors of hydrocarbon come out as a result of absorption of a shorter wavelength (green and blue) earlier to absorption of long wavelengths (red and yellow). This particular absorption is correlated with fraction of complex aromatic molecules, for example, oil asphalt [44].

5.2.3 Scattering:

Attenuation of light that results from the presence of particles or drilling mud mixed with reservoir fluid, where the light beam interacts with particles in the fluid and deflect from the beam, then the light transmission and the optical density measurement will be affected (reducing optical transmission). It can depend on the light wave- length. The scattering intensity depends on the scattering particles` size relative to the light wavelength [24], [45].

5.3 Compositional fluid measurements:

The fluid compositions in the flowline are analyzed into three hydrocarbon groups: (methane (C_1), gases hydrocarbon ($C_{2\text{-}5}$), and liquids hydrocarbon (C_{6+})). CO_2 is later to be treated. The near-infrared spectral analysis carried out on the downhole wireline tool is primarily focused on the near-infrared bands that correspond to the molecular vibrations [46]

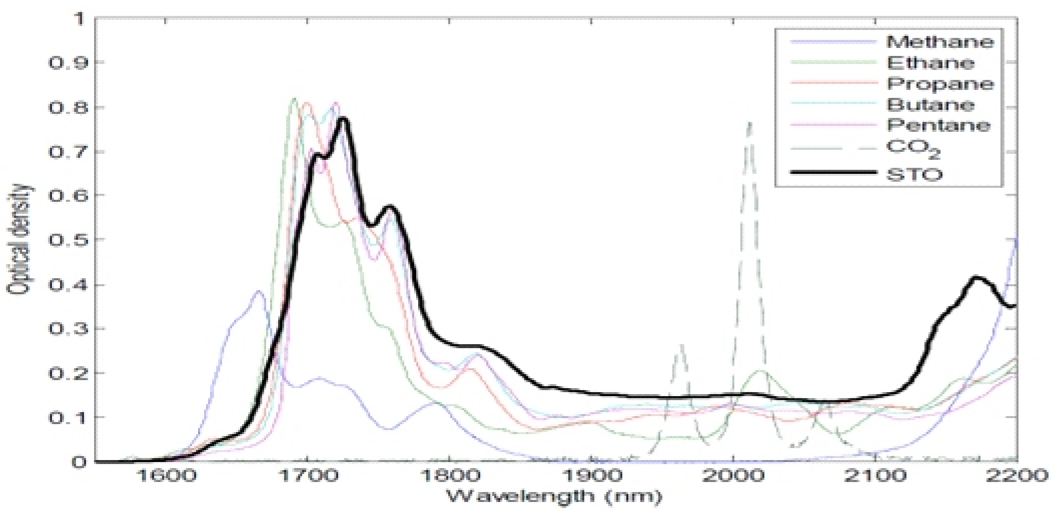


Figure 9: Optical absorption of different hydrocarbon components and stock tank oil (STO) [45]

Fig. 9 shows the light hydrocarbon absorbance spectra, storage tank oil, and CO_2 in the NIR region. The structural groups in the oil corresponding to organic compounds (CH_4), CH_3, and -CH_2 excite vibrational overtones and induce the light absorbance at different wavelengths. The composition of the light hydrocarbons can be determined from the structural group fraction, where the concentration of CO_2 is calculated from the individual structural group. Since H_2S and nitrogen are not visible in this wavelength range, it might influence depending on the concentrations of the other components [39].

5.4 In-situ GOR measurements:

An in situ downhole GOR calculation technique is developed for live crude oil by the use of real-time crude oil components and methane optical properties. Fig. 10 indicates many live oil distribution, GORs, methane, and dead oil. The peak at about 1660 nm is because of the methane molecules` vibrational absorption that are the key constituent in the gaseous phase when the crude oil flashes under normal conditions. The peak close to 1730 nm is because of CH_2 group's vibration absorption, that is the main components of many crude oils' molecular structure. When GOR rises that means the fraction of methane rises too and the fraction of oil declines, and therefore the peak of methane rises, and the peak of oil reduces as seen in Fig. 10.

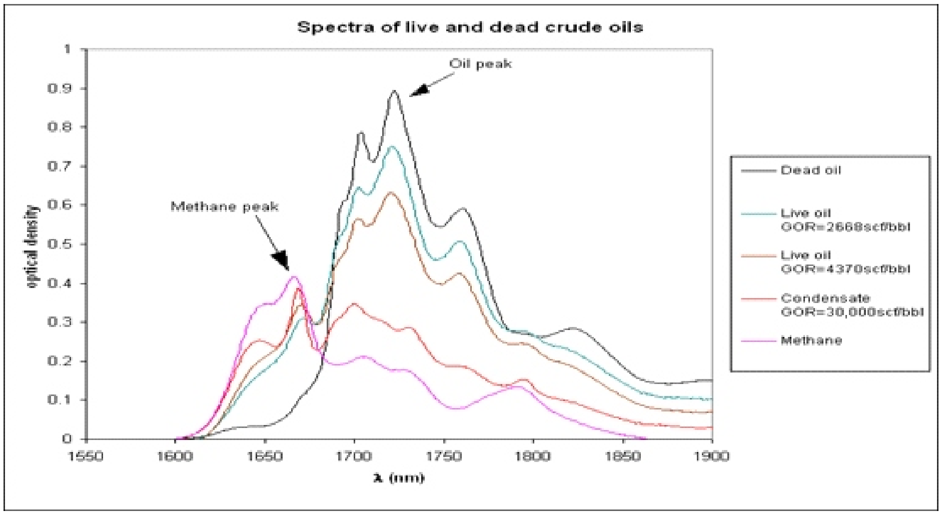
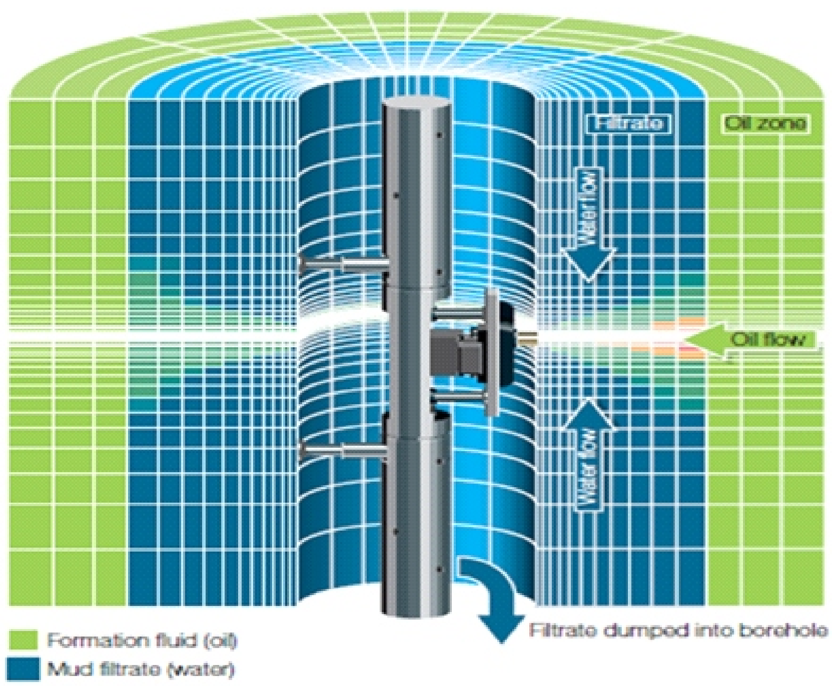


Figure 10: spectra for live crude oil

A study by Mullins demonstrated the peak magnitude of methane is proportional to the density of methane, and similarly, the peak magnitude of oil is proportional to oil density. The peak ratio of methane to oil can therefore be utilized to measure the gas to liquid mass ratio, then from the mass ratio, the GOR is measured. The live fluid analysis tool is covering the peaks of methane and oil as a channel, and such channels are utilized in order to measure GOR from live crude oils [47], [48]. GOR can be calculated by the following equation:

$$GOR = 8930\frac{m_m}{m_o - 0.193m_m} \text{ scf/bbl} \tag{4}$$

The measurements of DFA generally agree with laboratory results within the tool accuracy and lab uncertainties, especially for volatile oils, gas-condensate, and low GOR black oils fluids. Except for a few cases, lab and DFA differs significantly from each other. For highly undersaturated oils, the DFA GOR is consistently lower in some reservoirs than the lab value by 15-20 % [39].



water filtrate Fig. 11: Simulated fluid flow around a single probe during sampling [24]. A radial section map indicates saturation of formation close to the probe, (red) oil coning to the probe while pumping of samples and (blue) represent.

Oil wells are drilled with a drilling fluid which may be either oil or water based. Some filtrates from the drilling mud enter the formation forming an annular region around the well. A Clean sampling of formation fluids involves a good sample configurations and adequate pumping times to get rid of the filtrate, DFA will monitor and quantify contamination of the liquids filtrate [49]. Many authors study the possibility of obtaining minimum or zero contamination [50], [51]. Accurate analysis of formation samples by composition and PVT involves the obtained sample to keep under conditions of a downhole formation. This means a single-phase sample is maintained. Several sampling bottles of fixed volume can be used to take fluid of single phase and under reservoir conditions [24].

The temperature decreases during sampling, as the tool is removed from the wellbore to the surface. The drop-in temperature of the sample may lead to an inevitable decline in sample pressure due to the fixed volume [52] which lets the sample move through the bubble point and the gas releases, also will lead to asphalt precipitation. Asphalt deposition is possibly a very known documented issue at the time of crude oil recovery in the reservoir, wellbore, and process lines [24]. Recombining the gas and liquid phases at the surface is relatively easy for samples with no asphalt to get a single-phase sample again. In some cases, with agitation at the conditions of the reservoir, the asphalt particles will completely return to the solution, and in other cases, the asphalt will only partially re-solubilize. This problem can be avoided by collecting the sample at the surface without pressure decreasing [53], [54].

One solution to this problem being developed by Schlumberger, where the method involves over-pressuring the samples after being taken under the conditions of the reservoir to compensate for the decrease in temperature which induces drop in pressure when the samples return to the surface. The designing of the single-multisampling chamber is used along with the multi-sampling module.

7. Example:

Fig. 12 indicates the DFA results of a North Sea well. It can be seen that the composition within the same zone had changed with depth. The result was that DFA identified a large compositional gradient in real-time in the two zones of oil and gas [55]. The lowest depth of oil consists mostly of C6 + and thus hold a GOR in the column lower than the shallower depth fluid. The fluid composition analyzer determined that the gas/oil ratio differed by fifty

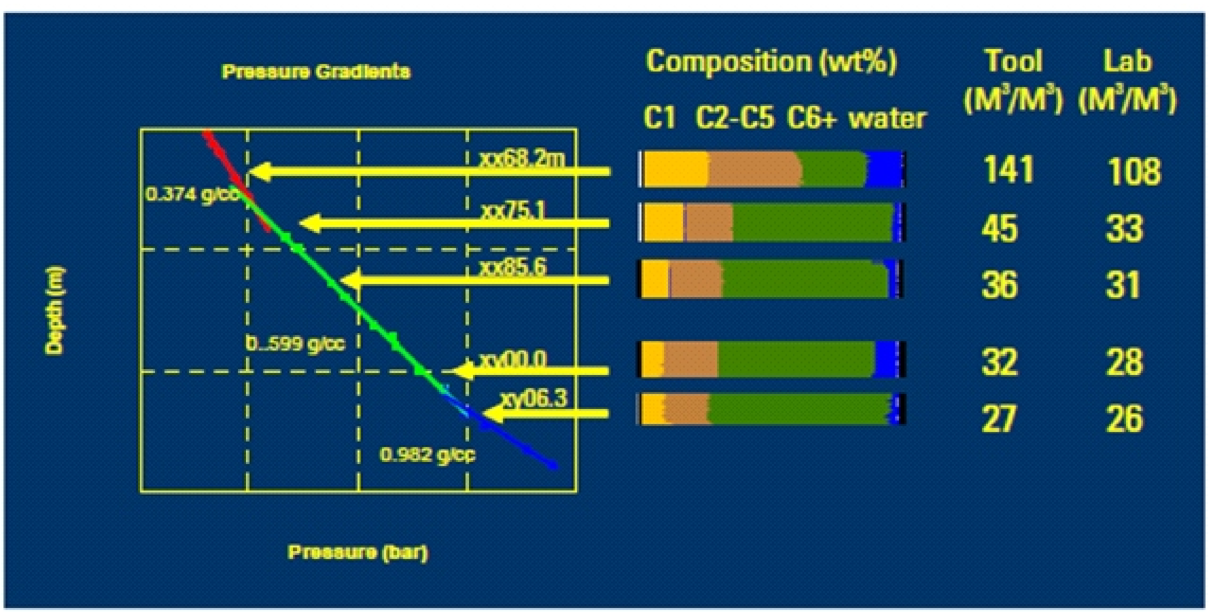


Figure 12: WFT and DFA data [56]

Percent over the 30-meters oil interval. The presence of a large variety of fluid from the pressure gradient was not apparent. The fluid composition analyzer tool was used to indicate the existence of a fluid gradient during this job on the bottom part of the oil interval, and a lower GOR was monitored. The work was subsequently amended for GOR testing along with the interval. Confirmation was established; the 30-m oil column measured a 50 percent monotonic variation in GOR. The results showed the analysis data in real-time. Those analyzes approved a large compositional gradient in the oil interval. In the gas cap, both the DFA and the laboratory analysis showed a higher GOR than in the oil column [57]. The compositional gradient determination led to better reservoir understanding and modeling. The large composition gradients indicated that the pressure gradient curve is curved, not a straight line, and that cannot be identified by the data of pressure alone [55].

8 Conclusion:

1. In addition to the traditional techniques such as pressure gradient analysis, DFA provides the additional characterizing capability for the reservoir. WFT sampling plays a vital role for both downhole and laboratory scale.
2. In situ characterization of formation fluids sample allowing the use of the sampling tools efficiently and enabling a good characterization of hydrocarbon fluids regarding both compositional grading and reservoir compartmentalization.
3. The in-situ analysis results are comparably the same as PVT lab results but there is 10 - 20% difference in high GOR reservoir fluid (The GOR from the lab results is less than DFA).
4. The example briefly showed the utilization of data from DFA and WFT and their application in reservoir management and formation evaluation.
5. DFA technology helps in providing in situ fluid prosperities early in the project and enabling faster evaluation of reservoir potential.

9. Nomenclature

GOR	Gas oil ratio
K_v	Vertical permeability
K_h	Horizontal permeability
cc	Cubic centimeter
mD	Millidarcy
C	Wireline formation tester shape factor
q	Flow rate
μ	Fluid viscosity
Δp_{ss}	Steady state drawdown pressure
K_{dd}	Permeability from draw down
IPTT	Interval pressure transit test
nm	Nanometer
D	Optical density
T	Transmittance
m_m	Methane mass fraction
m_o	Dead oil mass fraction
scf	Standard cubic foot
bbl	Barrels

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