

IPTC 10034

Coarse and Ultra-Fine Scale Compartmentalization by Downhole Fluid Analysis

Oliver C. Mullins,¹ Go Fujisawa,¹ Hani Elshahawi,² Mohamed Hashem²

1. Schlumberger Oilfield Services

2. Shell International Exploration and Production, Inc.

Copyright 2005, International Petroleum Technology Conference

This paper was prepared for presentation at the International Petroleum Technology Conference held in Doha, Qatar, 21–23 November 2005.

This paper was selected for presentation by an IPTC Programme Committee following review of information contained in a proposal submitted by the author(s). Contents of the paper, as presented, have not been reviewed by the International Petroleum Technology Conference and are subject to correction by the author(s). The material, as presented, does not necessarily reflect any position of the International Petroleum Technology Conference, its officers, or members. Papers presented at IPTC are subject to publication review by Sponsor Society Committees of IPTC. Electronic reproduction, distribution, or storage of any part of this paper for commercial purposes without the written consent of the International Petroleum Technology Conference is prohibited. Permission to reproduce in print is restricted to an abstract of not more than 300 words; illustrations may not be copied. The abstract must contain conspicuous acknowledgment of where and by whom the paper was presented. Write Librarian, IPTC, P.O. Box 833836, Richardson, TX 75083-3836, U.S.A., fax 01-972-952-9435.

Abstract

Encountering unexpectedly small compartment size has been one of the leading sources of production shortfalls in the petroleum industry. It follows that traditional methods to characterize compartments are substantially inadequate. Downhole Fluid Analysis (DFA) has recently been established as a new tool to address compartmentalization. In particular, the objective of an entirely new type of log, a continuous downhole fluids log, is being realized. Here, the combination of DFA with pressure measurement is shown to be very effective for compartment characterization. Compartments of startlingly small size are shown. The ability of thin barriers to hold off large depletion pressures is established. Methods are given to optimize the use of DFA coupled with pressure for characterization of compartments.

Introduction

Petroleum reservoirs can consist of flow units or compartments that are massive or quite small. This characterization does not describe the overall size of the reservoir but does enormously impact the ability to drain the reservoir. For pedagogic purposes, it is useful to relate reservoirs to objects of the mundane. A kitchen sponge is an open cell structure; the individual cells are connected so water can flow easily throughout the sponge. In reservoir lexicon, the sponge is a single compartment. A single hole or well placed in the sponge could drain the entire contents of the sponge. On the other hand a spool of bubble wrap is a closed cell system. Fluids cannot flow from one bubble or cell to another. Indeed, if a knitting needle penetrated through the spool of bubble wrap, only those cells that are penetrated would drain. The spool of bubble wrap is highly compartmentalized, again in the oil field lexicon.

Oil reservoirs can be highly compartmentalized. Wells placed in such an environment will initially flow vigorously, as the small compartments often are at high pressure. However, the volume of drainage in highly compartmentalized reservoirs is small, so the wells stop flowing sometimes in months. If the econometrics of field development anticipated 10 years of well life, then major economic losses follow. In deepwater, the risks and rewards are of large scale; corresponding losses due to such unexpected compartmentalization are unacceptable. One method to determine the size of compartments penetrated by an oil well is to do an extended well test. Pressure vs. flow data can then be used to determine overall compartment shape and size. However, extended well tests are expensive with internal costs to an operating company sometimes exceeding \$100 million. With this cost structure, well tests, if initiated, are often terminated due to mounting costs prior to the well test objects being completed.

A much less costly but fundamentally flawed logic has been employed to reveal different compartments. It is accurately recognized that if two permeable zones are not in pressure communication, then they are not in flow communication. That is, pressure is a necessary condition for flow communication. However, pressure communication is not a sufficient condition to establish flow communication. Pressure communication can be established on geologic time; however, operating companies need to drain reservoirs in a 10-year time frame, not 10-million years. In addition, pressure communication has relaxed permeability requirements whereas flow communication requires much higher permeability. Consequently, the concept that pressure communication implies flow communication is in error by about nine orders of magnitude. This large technical error has led to compartmentalization being one of the leading sources of costly errors in the industry. One reason for persistence of this problem is that compartmentalization is bad news. How hard does one look to find bad news? It is difficult to be the bearer of bad news, especially without simultaneous identification of solutions.

An additional major concern in the production of oil is the existence of large compositional variations of hydrocarbons vertically and/or laterally within the field. [1,2] Shell finds it prudent to consider hydrocarbon fluids to be compositionally graded until proven otherwise. Fluid gradients can result from many different physical origins [3] such as gravity, thermal gradients, biodegradation, current reservoir charging, water

washing, and leaky seals. For example, large variations of viscosity in a heavy oil column are routinely produced in part from biodegradation. [4] Mobility varies inversely with viscosity so it is essential to identify possible large viscosity variations. In production, miscible flooding and production below a phase transition also produce compositional gradients. Many of these mechanisms that produce compositional grading drive the hydrocarbon column away from equilibrium. Consequently, one cannot collect a single sample and model the fluid variations in the column. For example, many deepwater turbidites are currently being charged. A steady state exists in the reservoir, but not equilibrium. In order to understand compositional variations in such a column, many samples are required.

In principle, laboratories can identify fluid compositional gradients. And in principle, geochemical and other analytical methods applied to hydrocarbon fluids can uncover compartmentalization. The problem is that without a priori knowledge that fluid complexities exist, the cost of comprehensive multiple sample acquisition and lab analysis is prohibitive. In addition, due to frequent fluid discrepancies involved in sample acquisition, transfer and lab analysis, redundant samples are routinely processed further adding to the cost. What is needed is a new, cost effective technology to reveal fluid complexities where costs are commensurate with the value of the information.

Downhole Fluid Analysis

DFA is a concept, not a particular tool. Currently, DFA relies on near-infrared spectroscopy (NIR). The details of NIR application for DFA have been described elsewhere. [5,6]

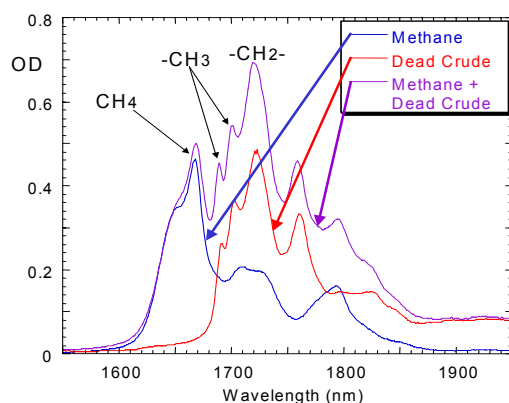


Figure 1 shows the absorption spectra (optical density (OD) vs. wavelength) of methane, a dead crude oil and a live crude oil. Methane and other alkane absorption features are readily distinguishable enabling some compositional information to be obtained.

Figure 1 shows the two-stretch overtone peak of different chemical groups containing the C-H oscillator. As is true for all mechanical oscillators, the oscillation or vibration frequency depends on the (reduced) mass. Consequently, CH_4 , $-\text{CH}_3$ and $-\text{CH}_2-$ groups all have somewhat different

frequencies allowing their resolution. As described previously, these chemical groups project into methane (C1), other hydrocarbon gases (C2-C5) and hydrocarbon liquids (C6+). [5,6] Other DFA measurements include index-of-refraction for gas detection [7] and fluorescence for retrograde dew detection. [8,9]

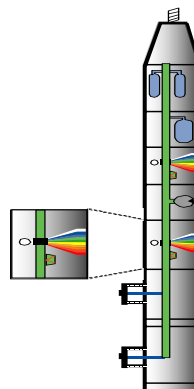


Figure 2. Schematic of the MDT with two optical modules to perform downhole fluid analysis. The optical modules are depicted with rainbows to convey optical spectroscopy.

Figure 2 shows the Modular Formation Dynamics Tester (MDT*) that brings fluids from the formation into the tool for analysis and acquisition purposes. Two single probes are shown at the bottom of the tool string; these probes attach to the borehole wall to extract fluids from the formation. Figure 2 shows the MDT with two DFA tools in the string. DFA is performed on the MDT with the tools the LFA*, [10] CFA* [11] and the LFA-pH*, the new optical pH tool [12] for water analysis. These optics tools employ the tool architecture of the OFA* (Optical Fluid Analyzer). The currently preferred tool configuration for OBM wells is shown in Fig. 2; the LFA is deployed upstream (below) the pumpout module of the MDT. This enables OBM-filtrate contamination monitoring without interference from pumpout dead volumes. The CFA is deployed downstream (above) the pumpout; the residence time of fluids in the pumpout allows for gravity segregation of the fluids, this process often improves CFA analysis performance. Thus, fluid and phase analysis are positioned in both the low-pressure and high-pressure side of the pumpout.

Figure 3 shows log data from a DFA tool. The absorption spectrum is shown; the spectral range spans the visible and NIR. Pumping time runs vertical in Fig. 3; here only one fluid is seen flowing through the tool. In each of the 10 wavelength channels, increasing line thickness indicates increasing absorption. Valid sample acquisition and sample identification are significantly enhanced by DFA. DFA methods are used to quantify miscible contamination. [10,13,14] Detection of deleterious phase transitions of gas [7] and retrograde dew [8] can be avoided via direct detection methods; at the same time these analyses enable fluid identification. Using the LFA and CFA, the GOR of black oils, volatile oils and condensates are measured, some hydrocarbon composition is determined, and fluorescence measurements are made for fluid characterization. [8,10,11,15]

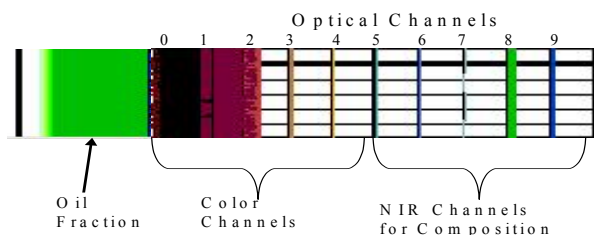


Figure 3 depicts log data from the simplest of the optics tools showing optical channels measuring fluid coloration and the NIR spectrum. Increased absorption is shown as increasing line thickness in the display, increasing pumping time runs vertical. An interpreted oil fraction is shown on the left.

In a general sense, the analysis of hydrocarbon fluids in real time during wireline logging is known to be an important objective. [16] DFA enables the analysis of hydrocarbon fluids at small marginal cost. If a hydrocarbon fluid sample is found to be similar to a fluid elsewhere in the column, then the sample need not be collected for subsequent laboratory analysis. That is, a fluid can be brought into the tool, analyzed, and then discarded if a laboratory analysis is not needed. Shell has termed this process 'gargling'. [17] On the other hand, if fluid complexity is found that warrants laboratory analysis, then samples are acquired. Thus, DFA reveals hydrocarbon complexities and enables acquisition of important samples thereby improving the efficiency and effectiveness of hydrocarbon analysis.

Continuous Downhole Fluid Log

The overall objective is to generate a new kind of log for the petrophysicist - a continuous downhole fluids log. [18] In the same spirit that pressure station measurements can be used to generate a pressure gradient, DFA station measurements can be used to generate a (quasi) continuous downhole fluids log. A crucial feature of the DFA method is that the DFA analysis program can be increased without logistical constraint to match the complexity of the hydrocarbon fluid column. For complex columns, many DFA stations are needed, often exceeding 15, employing the gargling technique. In these cases, the expanded understanding of the fluid column is deemed well worth the marginal increases in cost associated with the additional DFA stations.

Fluid variations are rapid with location in the column at phase boundaries, fluid contacts and permeability barriers. Compositional variations not associated with these discontinuities tend to be less rapid. One acquires a large number (per unit depth) of DFA stations at suspected fluid discontinuities and a lower number (per unit depth) of DFA stations in continuous fluid columns. Thresholds for compositional variations can be set between DFA stations; if the threshold is exceeded, an intervening DFA station can be obtained.

DFA Reveals Compositional Variations & Compartments

By acquiring multiple DFA stations in a hydrocarbon column, large compositional variations have been found. For example, a ~50% variation in GOR was found in a 30 meter column of oil. [11] This fluid variation was not evident in the pressure gradient data but was confirmed by various means including acquisition of > 40 MDT samples. In addition, this large compositional variation implies that the pressure gradient is a curved line, not a straight line. This curvature of the oil pressure gradient causes the modeled oil-water contact to shift down. This was validated with the MDT job by producing oil low in the column enabling the operating company to book more reserves. More subtle compositional gradients have also been observed using DFA. [18]

DFA is often much more sensitive to the detection of compositional gradients than determination of fluid density from pressure gradients. Density is an integral quantity, thus not as sensitive. Direct measurement of the gas-oil ratio, a proxy for hydrocarbon fluid density, [19] is much more sensitive. For example, comparing deep dry gas and shallow heavy oil, the contrast in fluid densities is about a factor of 5; deep gas is ~0.2 g/cc while heavy oil is ~1 g/cc. However, the variation for GOR goes from roughly zero for heavy oils to infinity for dry gas. The range of GOR is vastly bigger than the range of density for the same fluids. Issues such as depth correction, number of stations and height of the column impact pressure gradient accuracy but not DFA accuracy. To measure fluid properties by measuring pressure gradients is the wrong way around. [20] Instead, one should measure fluid properties to understand the fluid and check consistency with pressure gradients. [18] Both DFA and pressure measurements are required to understand fluid and reservoir complexities.

Compartmentalization is also addressed by DFA. First, hydrocarbon fluid density inversions are routinely discovered. [18,21] That is, more dense fluids are found higher in the column. Since density inversions are not likely to be sustained for geologic time in a single compartment, it is likely these density inversions reflect vertical compartmentalization. This finding is in concert with a zeroth order reservoir charging scenario which follows: the initial charge from a kerogen, its heaviest charge, [22] floats up to be trapped by a (large) cap rock. Kerogen enters the oil window at ~100°C. Of course the reservoir is not as hot, nor deep; the reservoir is not fully formed. As time and temperature progress forward, the reservoir compacts creating new seals lower in the column. Later in the kerogen catagenesis, the charge evolves to a lighter hydrocarbon that is then trapped lower in the column by new lower seals. This process produces density inversions that are often found within single horizons. In addition, zones containing disparate fluids may reflect compartmentalization even without density inversion. Virtually all reservoirs contain mixtures of different charges, even if from a single kerogen. [23] Furthermore, compartment identification is often more effective by analyzing light ends, as opposed to the traditional large (biomarker) molecule analysis. [23]

In this paper, we show the benefit of combining DFA with other log data to derive the most likely description of the hydrocarbon column. Emphasis is placed on understanding the compartment size. In particular, dramatic results are presented proving the existence of very small compartments. Other larger length scale compartments are indicated as well. Compartments are indicated in part by fluid density inversions and in part by other fluid considerations. The benefit is established of running DFA with pressure measurement after significant production. The impact on production of barriers established by DFA is shown.

Field Examples

Vertical and Lateral Compartmentalization. Figure 4 shows the results of the vertical seismic profile (VSP) of a potentially laterally extensive turbidite reservoir. A large extensive sand body was identified as indicated by the two white arrows in Fig. 4. The single sand body was intersected by two wells as shown. Some discretion existed in the processing of the VSP data such that two distinct scenarios could be considered. Essentially, the scenarios differed in the likelihood of lateral discontinuity. From a risk management point of view, the more plausible scenario needs to be more heavily weighted. As shown below, DFA establishes significant vertical compartmentalization. Lateral compartmentalization is viewed as very plausible.

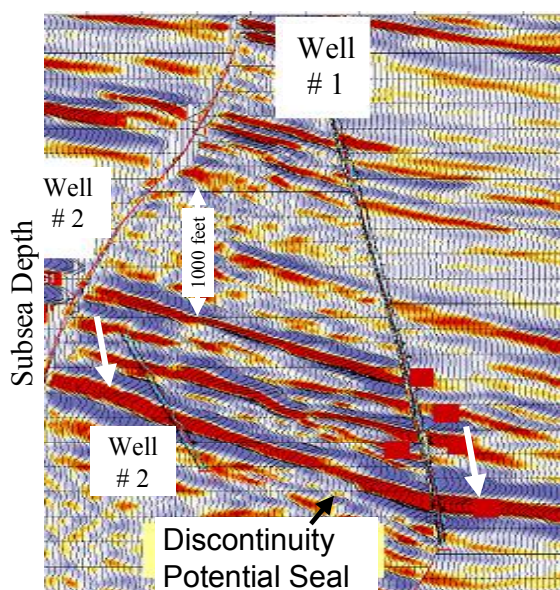


Figure 4. VSP processing showing a lateral discontinuity in the target sand; possibly this is a sealing barrier.

Figure 5 shows a suite of log data collected for Well #1. The logs are consistent with a sand fining upwards which is common with turbidity flows in deepwater.

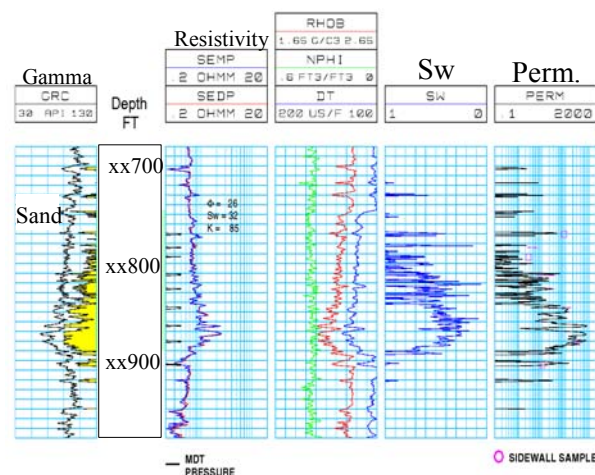


Figure 5 shows log results for the target sand body seen in Figure 4. The sand could be a fining-upwards sand body that is common in this depositional situation.

Figure 6 shows the pressure gradient data along with DFA logs. The pressure gradient is consistent with a water column, but resistivity indicates hydrocarbon. Thus, the simplest interpretation of the pressure measurements - a single pressure gradient - is suspect.

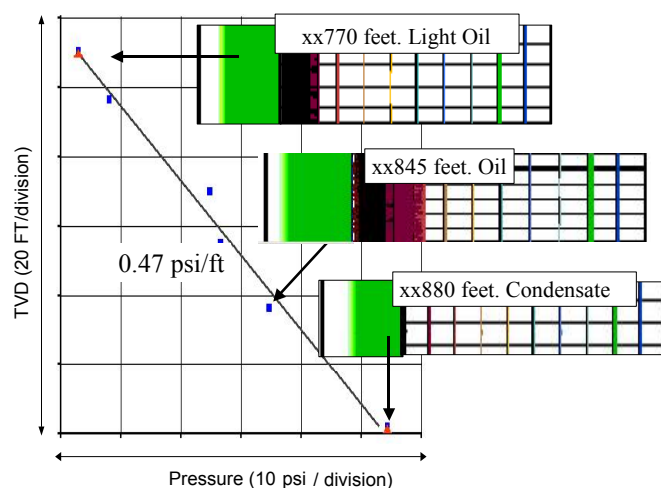


Figure 6. The pressure gradient indicates water if vertical communication is presumed, but DFA shows oil. The hydrocarbon fluid density inversion between xx845 and xx880 strongly indicates vertical compartmentalization.

DFA logs were run at three points in this sand; the OFA logs are shown in Fig. 6 for the three depths. In all cases, the OCM contamination analysis [10,13] shows that low contamination levels were achieved. Between the lower two stations in the column which are separated by 35 feet measured depth, there is a clear fluid density inversion. The oil higher in the column at xx845 feet is much darker in color, thus with more asphaltenes, thus is more dense, than the condensate at xx880 feet. Obviously, vertical compartmentalization is strongly implied. This vertical compartmentalization explains why the pressure data cannot be interpreted as a single gradient.

In addition, the fluids from the top two formations, xx770 feet and xx845 feet, are quite different. At the very high pressures in this well (>10 kpsi), it is unlikely to have a gas cap. Furthermore, the pressure measurements are inconsistent with a single gradient spanning the formations containing these different fluids. A steep compositional gradient in the 75 feet of measured depth for this moderately heavy oil is possible but was thought to be unlikely. Further vertical compartmentalization is plausible here. If greater risk reduction were needed, intervening DFA stations could have been deployed providing assurance on this issue.

Ultra-Fine Scale Compartment.

In a different field, well log data in Fig. 7 were acquired showing several hydrocarbon containing zones in the range X630 feet to X730 feet. The density-neutron crossover in Fig. 7 implies a very light hydrocarbon at X630 feet and X640 feet.

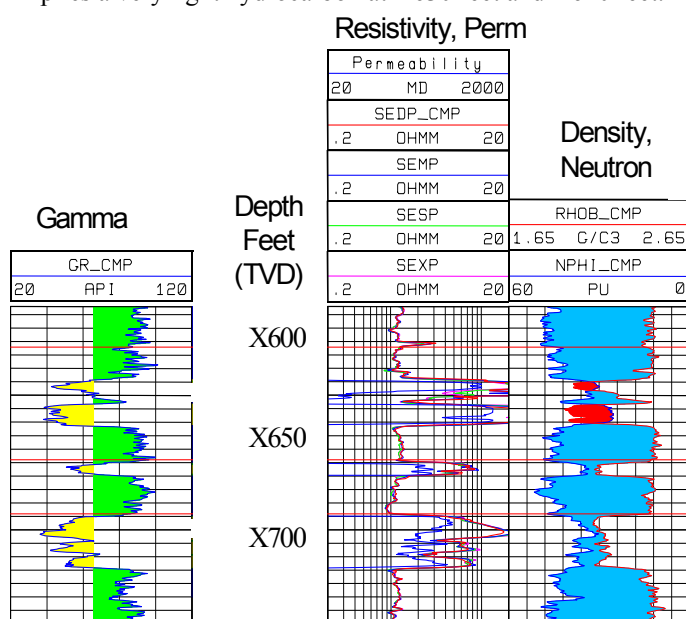


Figure 7. Log data showing several hydrocarbon containing sands.

Figure 8 shows the DFA data confirming the existence of a very light hydrocarbon at X640 feet, essentially a gas. The DFA log also shows a heavy oil at X700 feet. At these depths and pressures (>10kpsi) it is very unlikely that a gas cap could coexist with oil. Such a huge vertical variation of a monophasic fluid in 60 feet is also viewed as very improbable. Also, a third hydrocarbon intermediate in density and GOR was obtained at X670 feet further complicating the picture. Thus, vertical compartmentalization is likely. The question remains, what is the size of the compartments?

A remarkable observation was made while sampling at X640 feet. The pressure and pressure gradient for this sand body were determined prior to sampling as shown in Fig. 8. After sampling roughly 30 gallons, the pressure was measured again. A 50 psi pressure drop was recorded in this zone. To check that the pressure gauge did not somehow acquire a large offset, two pressure measurements were then repeated near

X625 feet. The same pressure and same pressure gradient at X625 feet were obtained before and after sampling at X640 feet. Thus, the measurement of the pressure drop was deemed accurate. Again, a second pressure point was acquired in the formation at X640 feet and indeed, a 50 psi pressure drop remained, yet the pressure gradient repeated before and after sampling.

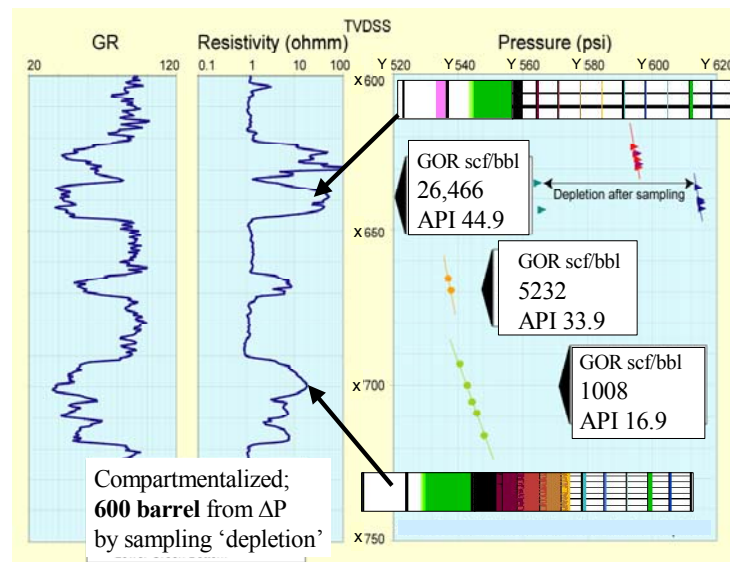


Figure 8. DFA indicates compartmentalized sands. 'Depletion' pressure drop with sampling shows compartment size is 600 barrels.

The most likely explanation for these observations is that a depletion pressure drop of 50 psi occurred. One can estimate the volume of the compartment knowing the volume produced (30 gallons) and the pressure drop (50 psi). Using an estimate of the compressibility of this gaseous hydrocarbon at these pressures (2.4×10^{-5} /psi), one obtains that the compartment size is ~600 barrels in place! This is a very small compartment. The pressure drop seen in the lower gas sand was not observed in the upper gas sand. These two sands are not in flow or pressure communication on the time scale of the MDT test.

Identification of a compartment of only 600 barrels is dramatic. Again, it is not the size of the total sand body that is being measured here but rather the size a flow unit in this sand body. The existence of a single 600 barrel compartment implies that there could be lots of small compartments in this formation. This length scale is beginning to approach that of whole cores where it is routine to find shales with entrapped sand volumes filled with oil but totally sealed. There can be so much entrapped sand that these formations are not truly shales. Nevertheless, they do not produce oil due to lack of any connectivity.



Figure 9 shows a photograph of the Fluorescence Logging Tool prototype [24]. This prototype used blue and red LED's to excite fluorescence along the borehole wall.

Using the Fluorescence Logging Tool prototype (cf. Fig. 9), a fluorescence log of a borehole wall has been obtained for a well in a totally different field. [24] Figure 10 shows an FLT log where the sandy shale showed continuous fluorescence. The fluorescence is from oil and not that from a source rock. [25] An examination of the whole core from this well showed that the shale contained sandy pockets some of which were a cubic inch in dimension. These little sand bodies were saturated in oil but were not connected in the least.

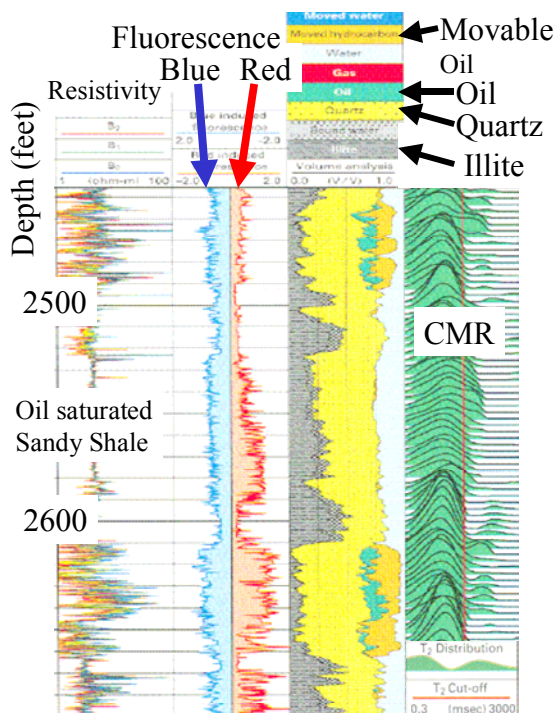


Figure 10. The fluorescence logging tool (FLT) and other log data. Note significant fluorescence originating in the shale; whole core analysis shows that the shale contains many small sand bodies saturated with oil.

A continuum picture is suggested regarding oil-containing sand bodies or compartments. Nature is not wedded to large producing units. In the past, an irrational exuberance prevailed regarding compartment size. Today, realistic assessment is the goal. The discovery here of a 600 barrel compartment and the realization that oil-containing sand bodies can be even smaller emphasizes the complexity of the geosphere and the perils associated with unsupported assumptions. If we take a million barrels as the size of a large compartment, and we take a cubic inch as the size of the oil-containing sand units found in Fig. 10, then the range in volume of these 'compartments' is roughly 10 orders of magnitude. This large range necessitates exploiting all available methods to delineate compartment size.

The ability to exploit fully the WFT (wireline formation tester) logging process shows the necessity of having one or more senior advisors monitoring these jobs in real time. Decisions are made in real time based on encountered complexities. The response to a puzzle is to acquire more data necessary for the resolution of the complexity; additional DFA stations, sampling stations and/or pressure stations are most clarifying. These obviously cannot be performed after the job is completed. The 'Monday morning quarterback' does not have the data necessary to resolve complexities. This WFT process breaks with previous tradition. In the past, it sufficed to send an excellent engineer to the rig for acquisition of excellent log data. All analysis could be done after the job was completed. With the WFT, this is much too later. A senior advisor is required to interpret and direct the logging program in real time.

Flow Barrier vs. Pressure Barrier.

We have already encountered the concept of pressure barriers being distinct from flow barriers (on production times). We have seen that these two concepts while seemingly similar actually differ by approximately 9 orders of magnitude in terms of physical constraints in the reservoir. Confusion here has led to enormous problems. The following question arises, if a flow barrier exists in the formation, will a depletion-induced pressure drop rupture the barrier? After all, it is generally understood that pressure seals in gas caps can have pressure-induced leaks.

Figure 11 presents data where a large shale break seemed to separate two sands. However, DFA clearly shows that the top part of the lower sand contains the same fluid as the top sand and is thus not communicating with the rest of the lower sand. After extensive production, a large depletion-induced pressure drop, about 2000 psi, occurred in this lower sand. Virgin pressure remained in the top section of this lower sand. It is not even evident in the log data what the seal is. This 'invisible seal' is able to hold off 2000 psi. This shows that at least sometimes, the flow units identified by DFA are very relevant for production. Presumably, there are cases where a pressure reduction from production will rupture sealing barriers. However, as Fig. 11 shows, such an occurrence cannot be presumed.

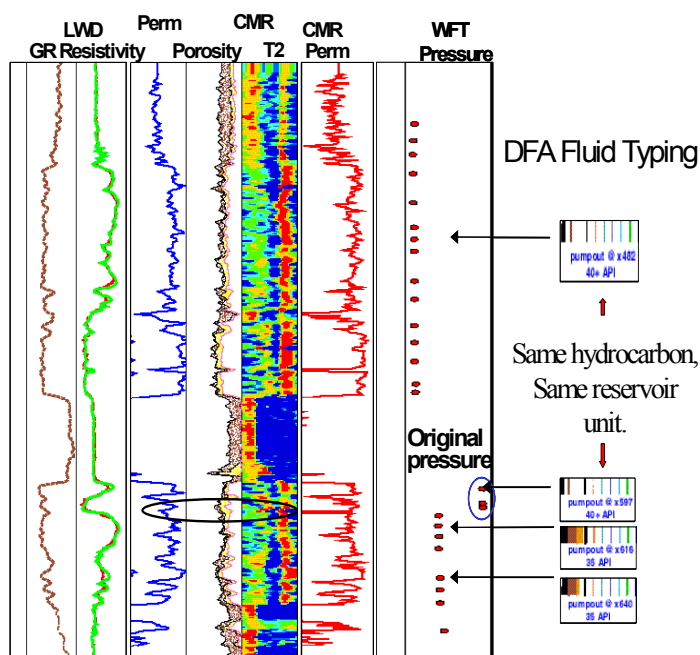


Figure 11. Log data showing a barrier seen in DFA but not other logs. The 'invisible' barrier is holding off 2000 psi of depletion pressure differential.

Conclusions

Downhole Fluid Analysis is a new type of log and is being exploited to address some of the most important issues in reservoir management, compartmentalization and compositional grading. The combination of DFA with other logging data is powerful as shown herein. The robust determination of the existence of a 600 barrel compartment in a seemingly 'normal' formation reinforces that outmoded and unsubstantiated optimism regarding compartmentalization is fraught with risk. Indeed, data is presented showing that oil-bearing sand units ('compartments') can be much smaller than 600 barrels. It is suggested that the range of compartment size is enormous and must be addressed at the outset of field appraisal and development. Compartmentalization revealed by DFA but not by other logs is shown in one case to seal against a 2000 psi depletion pressure drop proving relevance for production of this new log data. In addition, this paper demonstrates that the process of reservoir characterization requires direction *during* data acquisition by senior technologists. The goal of DFA is to create a continuous downhole fluids log from a series of discrete station measurements. This new type of log is proving its merits in many applications, but to be exploited fully, this process requires expert involvement.

References

- [1] J. Ratulowski, A.N. Fuex, J.T. Westrich, J.J. Sieler, "Theoretical and experimental investigation of isothermal compositional grading," SPE #84777, Dallas, TX, (2003)
- [2] L. Hoier, C.H. Whitson, "Compositional grading – theory and practice," SPE #63085, Dallas, TX, (2000)

[3] J.M. Cubitt, W.A. England, (Eds.) *The Geochemistry of Reservoirs*, Geological Society Special Publication No. 86, (1995)

[4] Koopmans, M.P., Larter, S.R., Zang, C., Mei, B. Wu, T., Chen, Y., Biodegradation and mixing of crude oils in the Liaohe Basin, China. Proceedings of the 19th International Meeting on Organic geochemistry, Istanbul. Extended Abstracts, 63, (1999)

[5] O.C. Mullins, T. Daigle, C. Crowell, H. Groenzin, N.B. Joshi, Gas-Oil Ratio of Live Crude Oils Determined by Near-Infrared Spectroscopy, *Applied Spectroscopy*, 55, 197, (2001)

[6] G. Fujisawa, M. Van Agthoven, P. Rabbito, O.C. Mullins, Near-Infrared Compositional Analysis of Gas and Condensate Reservoir Fluids at Elevated Pressures and Temperatures, *Applied Spectroscopy*, 56, 1615, (2002)

[7] O.C. Mullins, R.J. Schroeder, P. Rabbito, Gas detector response to high pressure gases, *Applied Optics*, 33, 7963 (1994)

[8] S.S. Betancourt, G. Fujisawa, O.C. Mullins, K.O. Eriksen, C. Dong, J. Pop, A. Carnegie, Exploration applications of downhole measurement of crude oil composition and fluorescence, SPE #87011, Asia, Pac. Tech. Conf. (2003)

[9] O.C. Mullins, Ch. 2, "Optical interrogation of aromatic moieties in crude oils and asphaltenes," in O.C. Mullins, E.Y. Sheu, (Eds.) *Structures and Dynamics of Asphaltenes*, Plenum Press, New York, NY, (1998)

[10] O.C. Mullins, G. Beck, M.Y. Cribbs, T. Terabayshi, K. Kegasawa, Downhole determination of GOR on single phase fluids by optical spectroscopy, SPWLA 42nd Annual Symposium, Houston, Texas, Paper M, (2001)

[11] G. Fujisawa, S.S. Betancourt, O.C. Mullins, T. Torgersen, M. O'Keefe, C. Dong, K. O. Eriksen, Large Hydrocarbon Compositional Gradient Revealed by In-Situ Optical Spectroscopy, SPE #89704, ATCE, (2004)

[12] B. Raghuraman, M. O'Keefe, K.O. Eriksen, L.A. Tau, O. Vikane, G. Gustavson, K. Indo, Real time downhole pH measurement using optical spectroscopy, SPE 93057, Int., Symp., Houston, TX, (2005)

[13] O.C. Mullins, J. Schroer, Real-time Determination of Filtrate Contamination During Openhole Wireline Sampling by Optical Spectroscopy, SPE Annual Technical Conference and Exhibition, Dallas, TX, (2000), 63071

[14] C. Dong, H. Elshahawi, O.C. Mullins, G. Fujisawa, A. Kurkjian, Advances in downhole contamination monitoring and GOR measurements of formation fluids, SPWLA, Paper FF, Galveston, TX, (2003)

[15] G. Fujisawa, O.C. Mullins, C. Dong, A. Carnegie, S.

Betancourt, T. Terabayashi, S. Yoshida, A.R. Jaramillo, M. Haggag, Analyzing Reservoir Fluid Composition In-Situ in Real Time: Case Study in a Carbonate Reservoir, SPE 84092, Denver, CO, (2003)

[16] M.N. Hashem, E.C. Thomas, R.I. McNeil, O.C. Mullins, Determination of producible hydrocarbon type and oil quality in wells drilled with synthetic oil-based muds, Society of Petroleum Engineers #39093, San Antonio, TX (1997); also published in SPE Reservoir Evaluation & Eng., #55959

[17] M.N. Hashem, H. Elshahawi, G. Ugueto, A Decade of Formation Testing - Dos and Don't and Tricks of the Trade, SPWLA 45th Ann. Log. Symp. June 6-9, The Netherlands, (2004)

[18] O.C. Mullins, H. Elshahawi, M.N. Hashem, G. Fujisawa, Identification of vertical compartmentalization and compositional variation by downhole fluid analysis; towards a continuous downhole fluid log, SPWLA 46th Ann. Log. Symp. June 26-29, Paper K, Houston, TX (2005)

[19] W.A. England, A.H. Muggeridge, P.J. Clifford, Z. Tang, Modelling density-driven mixing rates in petroleum reservoirs on geologic time scales, with application to the detection of barriers in the Forties Field, in reference 4.

[20] A. Stephen, PVT and Tracer Advisor, British Petroleum, Private communication.

[21] O.C. Mullins, M. Hashem, H. Elshahawi, G. Fujisawa, C. Dong, S.S. Betancourt, T. Terabayashi, Hydrocarbon compositional analysis in-situ in openhole wireline logging, SPWLA 45th Ann. Log. Symp. June 6-9, The Netherlands, (2004)

[22] B.P. Tissot, D.H. Welte, *Petroleum Formation and Occurrence*, Springer-Verlag, Berlin, Germany (1984)

[23] A. Wilhelms, S. Larter, Shaken but not always stirred. Impact of petroleum charge mixing on reservoir geochemistry, pp 27-35, in J.M. Cubitt, W.A. England, S. Larter, Understanding Petroleum Reservoir, towards an integrated reservoir engineering approach, Geological Society, London, 237, (2004)

[24] O.C. Mullins, X. Wu, T. Terabayashi, Private Communication, See also the Well Evaluation Conference, Caracas, Venezuela, J.M. Singer (Ed.), 1997

[25] J. Wang, X. Wu, O.C. Mullins, Fluorescence of limestones and limestone components, Applied Spectroscopy 51, 1890 (1997)