Oil-Base Mud Filtrate and Hydrogen Index Effects on Magnetic Resonance Porosity in Gas Reservoirs*

Stanley Oifoghe[1], Victor Okowi[1], and Holger Thern[1]

Search and Discovery Article #42332 (2018)**
Posted December 17, 2018

*Adapted from slides taken from poster presentation given at 2018 AAPG International Conference and Exhibition, Cape Town, South Africa, November 4-7, 2018.
 DOI:10.1306/42332Oifoghe2018

[1]Baker Hughes, a GE company, Port Harcourt, Nigeria (stanleyoifoghe@yahoo.com)

Abstract

Several drilling problems were encountered during the drilling of well A. The problems led to delays in drilling, and possible oil-based mud filtrate invasion in the gas-bearing reservoir sand. The client was unable to secure a license for use of radioactive sources in the determination of the sand porosity and hydrocarbon differentiation. Source-less logging-while-drilling (LWD) magnetic resonance porosity was a useful substitute for density and neutron porosity. In the absence of oil-based mud filtrate invasion, the expected under-call of the porosity because of low hydrogen index (HI) in the gas zone is corrected by modeling HI from reservoir pressure, temperature and gas composition.

The Magnetic Resonance Dual Wait Time (DTW) approach takes advantage of Longitudinal Relaxation Time (T1) contrast to solve for hydrocarbon saturation. "In light hydrocarbons, in a water-wetting reservoir, the hydrogen atoms in the hydrocarbon fluid relax slower than the non-movable and movable water. By using two polarization or wait times (Tw), it is possible to calculate hydrocarbon saturation using magnetic resonance tools" (Thorsen et al., 2008a,b).

Initial interpretation shows that the magnetic resonance-apparent porosity under-calls the true formation porosity. Using formation properties and the gas-specific gravity, predicted HI is 0.59. However, applying an HI of 0.59 to hydrocarbon volume causes a substantial over-estimation of the porosity. Therefore, it is necessary to determine an effective HI correction by correlating the magnetic resonance porosity with density, neutron or acoustic porosity from adjacent offset wells.

Using an interpretation of the T_2 peak position of the T_2 distribution on the magnetic resonance log of the well, the T_2 cut-off for irreducible water was shifted from 33ms to 100ms, to accommodate the longer relaxing irreducible water component affected by the wettability alteration from water-wet to oil-wet. Subsequently, an empirically derived HI of 0.8 was used to achieve a match of the magnetic resonance porosity of well A and density porosity of offset well B.

Introduction

During the drilling of well A, several drilling problems were encountered. The problems led to delays in drilling, and possible oil-based mud filtrate invasion in the gas-bearing reservoir sand. The client was unable to secure a license for use of radioactive sources in the determination of the sand porosity and hydrocarbon differentiation. Source-less logging-while-drilling (LWD) magnetic resonance porosity was determined to be a useful substitute for density and neutron porosity. In the absence of oil-based mud filtrate invasion, the expected under-call of the porosity, as a result of low hydrogen index (HI) in the gas zone, can be easily corrected by modeling HI from reservoir pressure, temperature, and gas composition.

Oil-based drilling muds have higher drilling rates and better wellbore stability. Among their additives are oil-wetting agents used to make the drilled cuttings and density control particles oil-wet to maintain the stability and rheology of the mud system. Potentially, these additives may invade into the near-wellbore formation and change the originally preferential water-wet mineral surface to mixed-wet or oil-wet. This alteration affects formation evaluation from magnetic resonance well logging.

Dual Wait Time (DTW)

The magnetic resonance Dual Wait Time (DTW) approach associates differences in Longitudinal Relaxation Time (T_1) [based on short wait time (T_w)] with various fluid types. Water has short T_1 and T_2; oil has longer T_1 and T_2; and gas has the longest T_1 and T_2. “In light hydrocarbons in a water-wetting reservoir, the hydrogen atoms in the hydrocarbon fluid relax slower than the non-movable and movable water” (Thorsen et al., 2008a,b). “Using two polarization times [wait times (T_w)]; it is possible to calculate hydrocarbon saturation using magnetic resonance tools. By using a long wait time, both the hydrogen atoms in the water and the hydrocarbons are polarized. By applying a shorter wait time, the hydrogen atoms in the water are polarized and only a small fraction of the hydrogen atoms in the hydrocarbons are polarized (Figure 1). If the bulk longitudinal relaxation of the hydrocarbon in pore space is known, hydrocarbon saturations can be estimated by following equations” (Thorsen et al., 2008a,b);

Long wait time: $$MPHS_L = \phi\, S_{HC}\, HI_{HC} \left(1 - e^{-\frac{TW_L}{T_{1HC}}}\right) + \phi\, (1 - S_{HC})\, HI_W\, P_W$$

Short wait time: $$MPHS_S = \phi\, S_{HC}\, HI_{HC} \left(1 - e^{-\frac{TW_S}{T_{1HC}}}\right) + \phi\, (1 - S_{HC})\, HI_W\, P_W$$

For $TW_L >> T_{1HC}$, the difference can be expressed as $$\Delta\varphi = \phi\, S_{HC}\, HI_{HC} \left(e^{-\frac{TW_S}{T_{1HC}}}\right)$$

Hydrocarbon saturation, ratio of HC porosity to total porosity, expressed as

$$S_{HC} = \frac{\Delta\varphi}{\phi\left(\mathrm{HI}_{\mathrm{HC}}\left[e^{-\frac{\mathrm{TW}_S}{T_{1HC}}}\right]\right)} = \frac{\Delta\varphi}{(\mathrm{HI}_{\mathrm{HC}}[\phi])}\left(e^{\frac{\mathrm{TW}_S}{T_{1HC}}}\right)$$

$MPHS_L$ [pu] –	Total porosity of the formation, bound and free fluid; derived from the echo train with long TW (ET_TWL)
$MPHS_S$ [pu] –	Total porosity of the formation, bound and free fluid; derived from the echo train with short TW (ET_TWS)
TW –	Wait time. The time needed to build up the magnetization, typically several seconds
TW_L –	Long wait time. The time needed to build up the magnetization for the entire fluid composition (Figure 1)
TW_S –	Short wait time. The time needed to build up the magnetization for the water fraction (Figure 1)
HI_{HC} –	Hydrogen index of hydrocarbon
HI_W –	Hydrogen index of water
Pw–	Polarization of water (equals 1 for TWL and TWS, since both TW are much larger than T_1, H_2O), illustrated in Figure 1
$\Delta\varphi$ [pu] –	Differences of total porosity (ET_TWL) and under-polarized porosity (ET_TWS), indicative of hydrocarbons; derived from differential echo train (ET_TWL – ET_TWS)
T_{1HC} –	Bulk longitudinal relaxation of the hydrocarbon in the pore space
S_{HC} [fraction] –	Hydrocarbon saturation, ratio of HC porosity to total porosity; derived from differential echo train signal including information T_1 of the hydrocarbon and total porosity
Φ –	Porosity

Results

Initial interpretation shows that the magnetic resonance apparent porosity under-calls the true formation porosity. Using formation properties and the gas-specific gravity, predicted HI is 0.59 (Figure 2). However, applying the HI of 0.59 to hydrocarbon volume causes an over-estimation of the porosity by 61% (Figure 3). This was attributable to the difficulty of separating oil-based mud filtrate invasion from the native gas signal, making it impossible to apply a hydrogen index correction of 0.59 to gas without applying a correction to the oil-based mud filtrate. It was necessary to determine an effective hydrogen index correction between approximately 0.59 (pure gas) and approximately 1 (pure oil-based mud filtrate) by correlating the magnetic resonance porosity with density, neutron or acoustic porosity from adjacent offset wells.

After several iterations to determine the T_1 and T_2 of the gas (Figure 4), a T_1 of 6000ms, T_2 of 3000ms and an empirically derived hydrogen index of 0.8 were used to achieve a match of the magnetic resonance porosity of Well A and density porosity of offset Well B. An attempt was also made to differentiate the oil-based mud filtrate from the gas (see Figures 5a, 5b, and 5c). This separation was, however, not feasible because of poor oil-based mud filtrate and gas T_1 and T_2 contrast.

The Transverse Relaxation Time (T_2) peak of the movable fluid correlated with the gamma-ray log. This can be attributed to a reduction in the T_2 peak position as a result of variations in permeability, which can be correlated with changes in the gamma-ray log as a result of changes in grain sizes. In the absence of any other effect, correction for porosity under-call can be effected if reference porosity is available, and the hydrogen index of the gas is known, assuming a constant gas versus oil-based mud filtrate saturation. Other than apparent surface relaxation, the effect can also be attributed to an internal gradient caused by the presence of paramagnetic minerals in the formation. Building a correlation of geometric mean of the transverse relaxation time (T_{2gm}) and gamma ray to gas versus oil-based mud filtrate saturation is necessary before applying the hydrogen index correction. The correlation was, however, not done because no other porosity logs were available in Well A.

The wettability alteration by the oil-based mud filtrate in the gas-bearing reservoir at irreducible water saturation, from water-wet to intermediate-wet or oil-wet, necessitated an increase in the T_2 cut-off value larger than the default cut-off value based on water-wetness because the irreducible water relaxes at a longer relaxation time. This does not significantly decrease the actual irreducible water but changes the water and gas relaxation time distributions because of wettability alteration (Chen et al., 2004). Based on the interpretation of the T_2 peak position of the T_2 distribution on the magnetic resonance log of Well A, the T_2 cut-off for irreducible water shifted from 33ms to 100ms (Figure 6) to accommodate the longer relaxing irreducible water component affected by the wettability alteration from water-wet to oil-wet.

Conclusions

Though planning yielded a hydrogen index correction of 0.59 for gas correction, an empirically derived hydrogen index of 0.8 was used to achieve a match of the magnetic resonance porosity of Well A and density porosity of Well B. The T_2 cut-off was adjusted to 100ms using the T_2 distribution interpretation with late movable fluid peak and medium-bound fluid peak. A comparison of the dual wait time hydrogen index-corrected porosity with the density porosity of the offset well shows a perfect match (Figure 7).

References Cited

Chen, J., G.J. Hirasaki, and M. Flaum, 2004, Effects of OBM invasion on irreducible water saturation: Mechanisms and modifications of NMR interpretation: SPE 90141-MS (presented at the 2004 SPE Annual Technical Conference and Exhibition, Houston, Texas, 26-29 September 2004).

Thorsen, A.K., T. Eiane, H.F. Thern, A. Kroken, M. Hansen, and F. Antonsen, 2008a, Enhanced net-to-gross understanding for horizontal-development drilling in complex, mature reservoirs: Society of Petroleum Engineers: SPE-10927-MS (presented at March-April Western Regional and Pacific Section Conference, Bakersfield, CA).

Thorsen, A.K., T. Eiane, H.F. Thern, P. Fristad, and S.M. Williams, 2008b, Magnetic resonance in chalk horizontal well logged with LWD: SPE-115699-MS (presented in September at annual Society of Petroleum Engineers Annual Convention, Denver, CO).

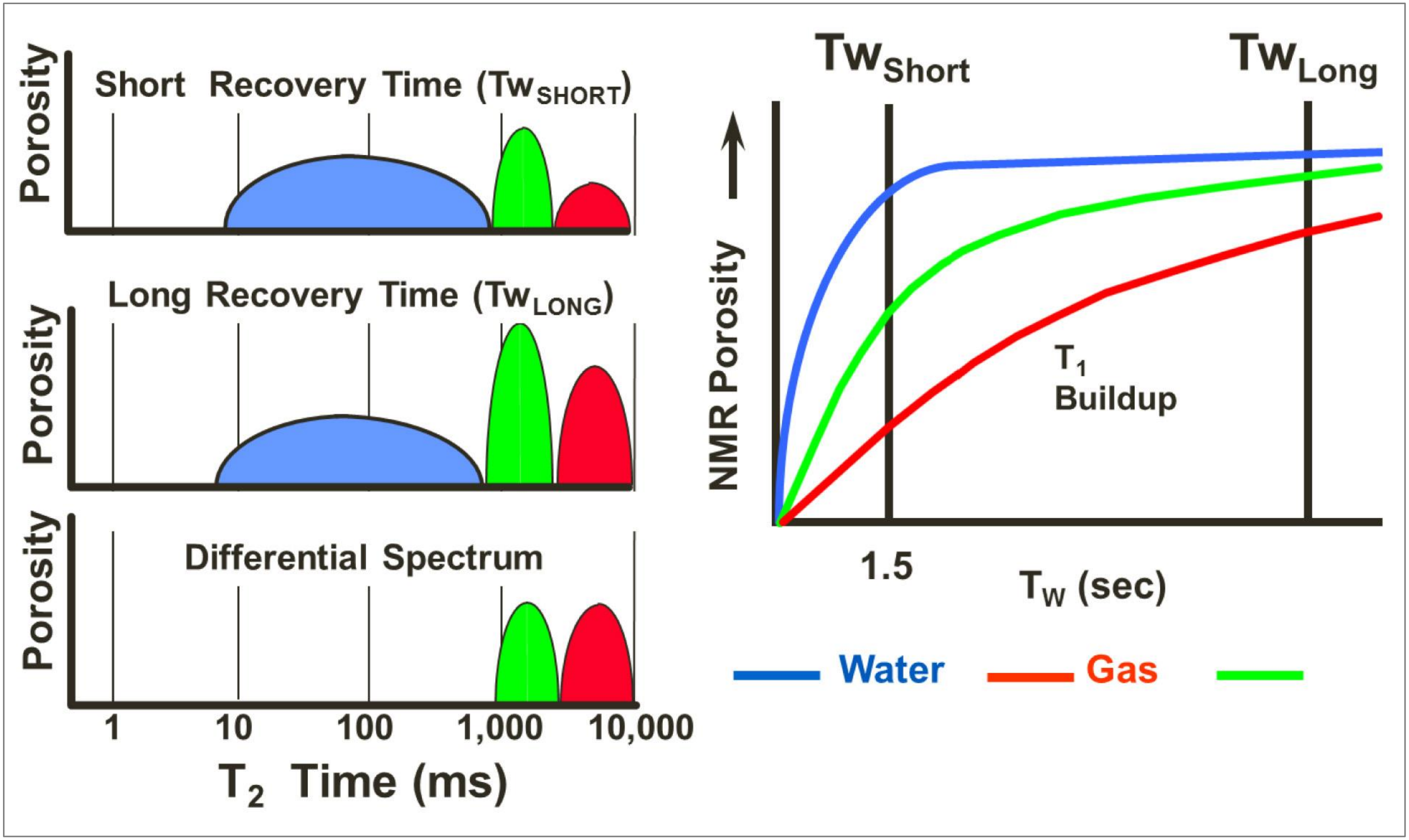

Figure 1. Dual Wait Time Methodology. The signal from water filled porosity is illustrated in blue, gas is in red, and oil is in green. On the right-hand side is the apparent NMR porosity as a function of wait time. At the short wait-time, the signal from the water filled porosity is almost completely recovered when compared to the long wait-time. On the left-hand side of the figure are illustrations of the T_2 relaxation spectrum for a short wait time, long wait time, and the differential spectrum. The water signal is absent from the differential spectrum because it is completely recovered for both the short and long wait times.

Property	Gas	Water	Oil	Dead Oil	Units
Temperature	219(103.89)	219(103.89)	--	--	F(C)
Pressure	9317(64.24)	9317(64.24)	--	--	psia(MPa)
Density	0.28	1.01	--	--	g/cm^3
Hydrogen Index	0.59	0.99	--	--	
Viscosity	--	0.28	--	--	cp
Diffusivity	53.09	9.08	--	--	10^(-9)m^2/s
GOR	--	--	--	--	SCF/STB
API Gravity	--	--	--	--	
Gas Specific Gravity	0.66	--	--	--	
Bulk T1	8377.7	13620.1	--	--	ms

Figure 2. Estimation of hydrogen index of gas from specific gravity. The estimated Hydrogen Index of the gas is 0.59.

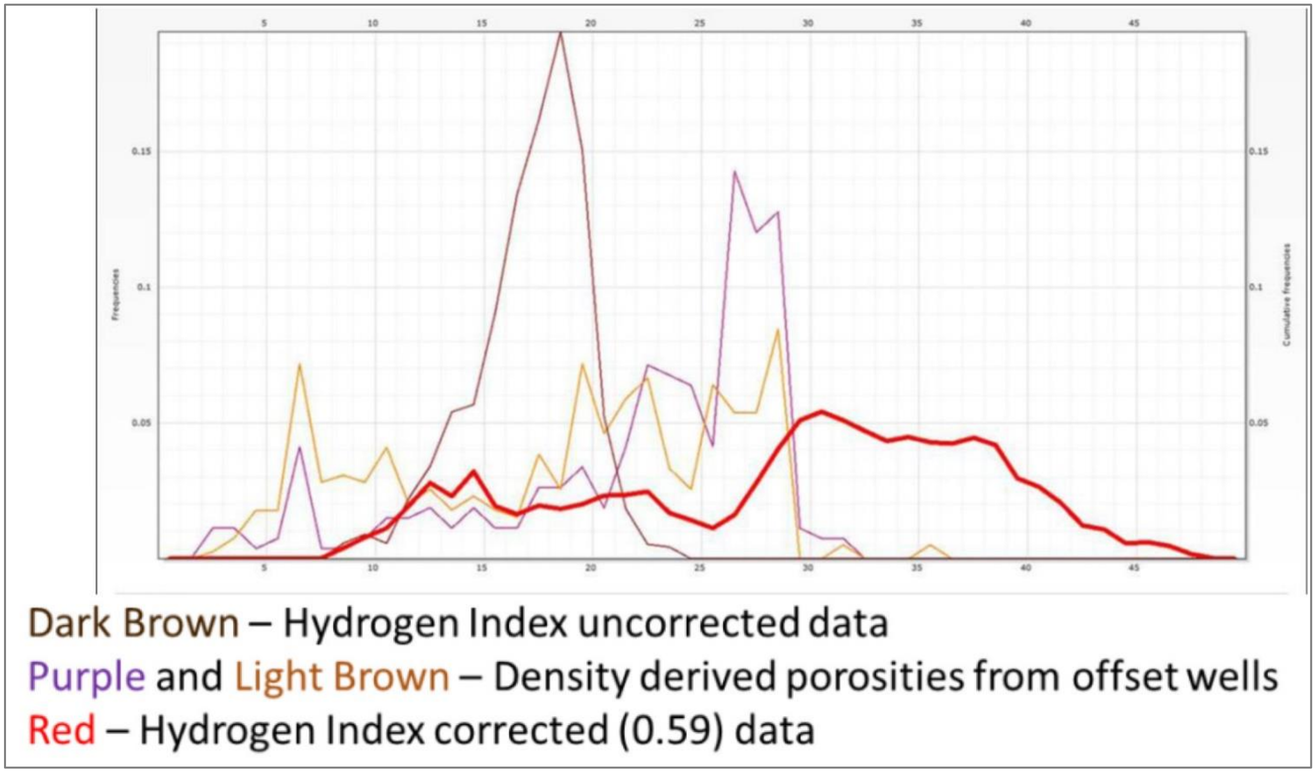

Figure 3. Comparison of uncorrected hydrogen index and corrected magnetic resonance porosity with density porosity from offset wells. Neither the uncorrected nor corrected magnetic resonance porosity matched with the density porosity from offset wells.

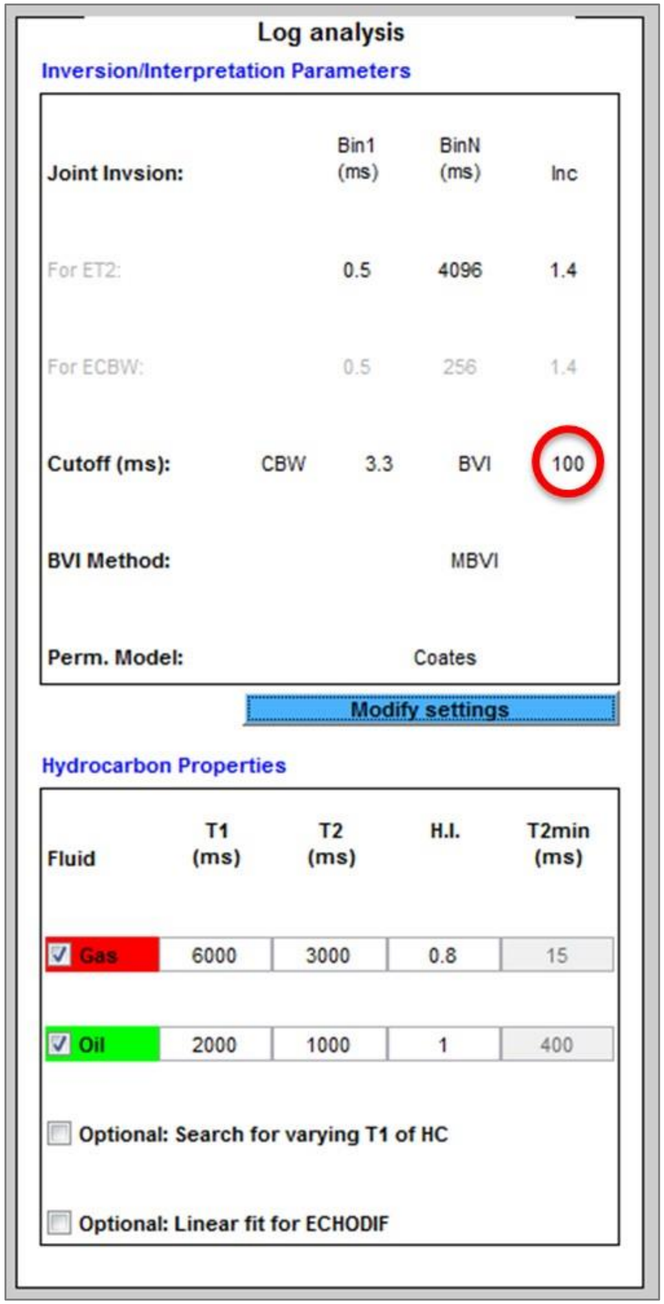

Figure 4. Dual wait time processing settings. The BVI cut-off was adjusted from the default of 33ms for clastic reservoirs to 100ms for this reservoir due to the longer relaxation time occasioned by the wettability alteration of the matrix from water-wet to oil-wet.

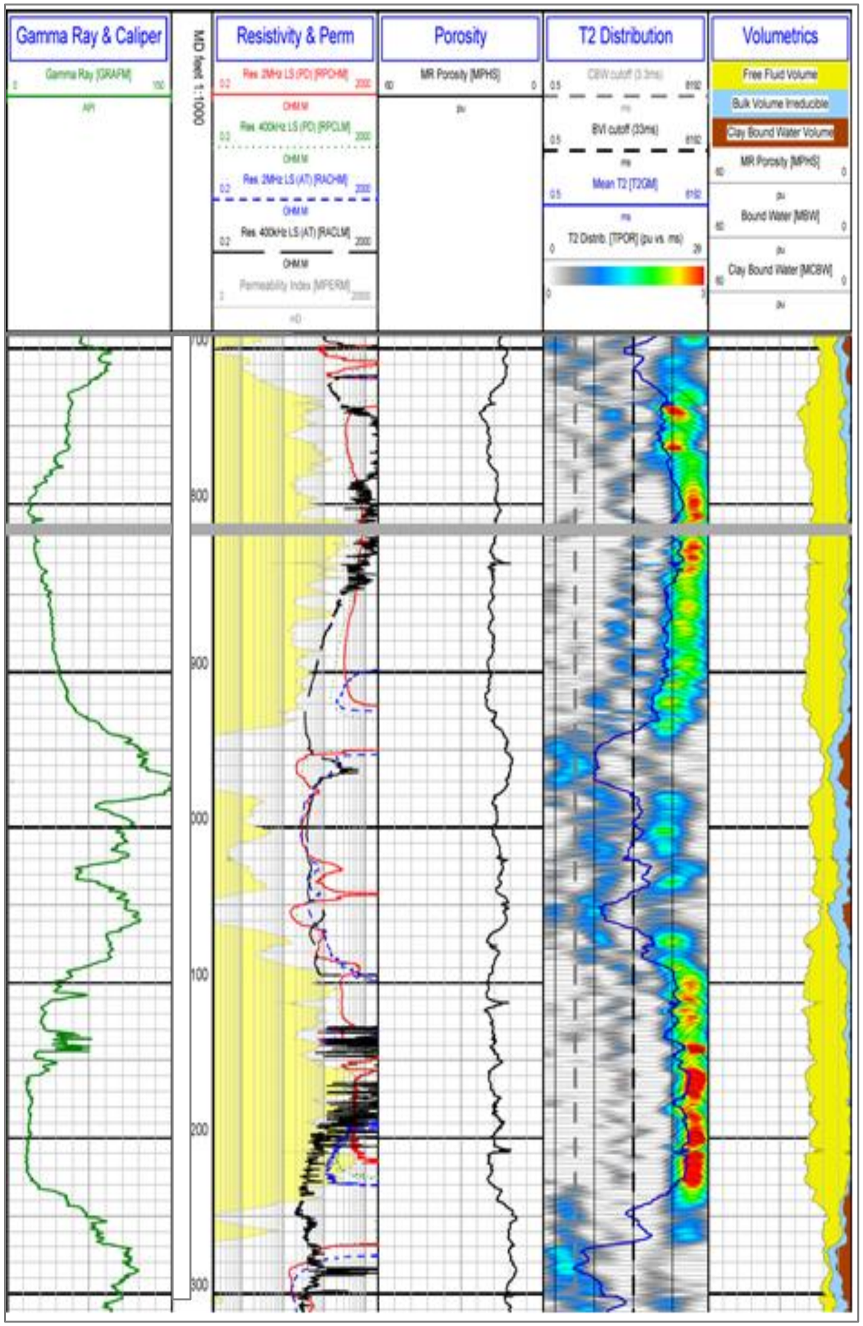

Figure 5a. Standard porosity and permeability without hydrogen index correction. Result shows porosity under-call with average total porosity value of 18pu.

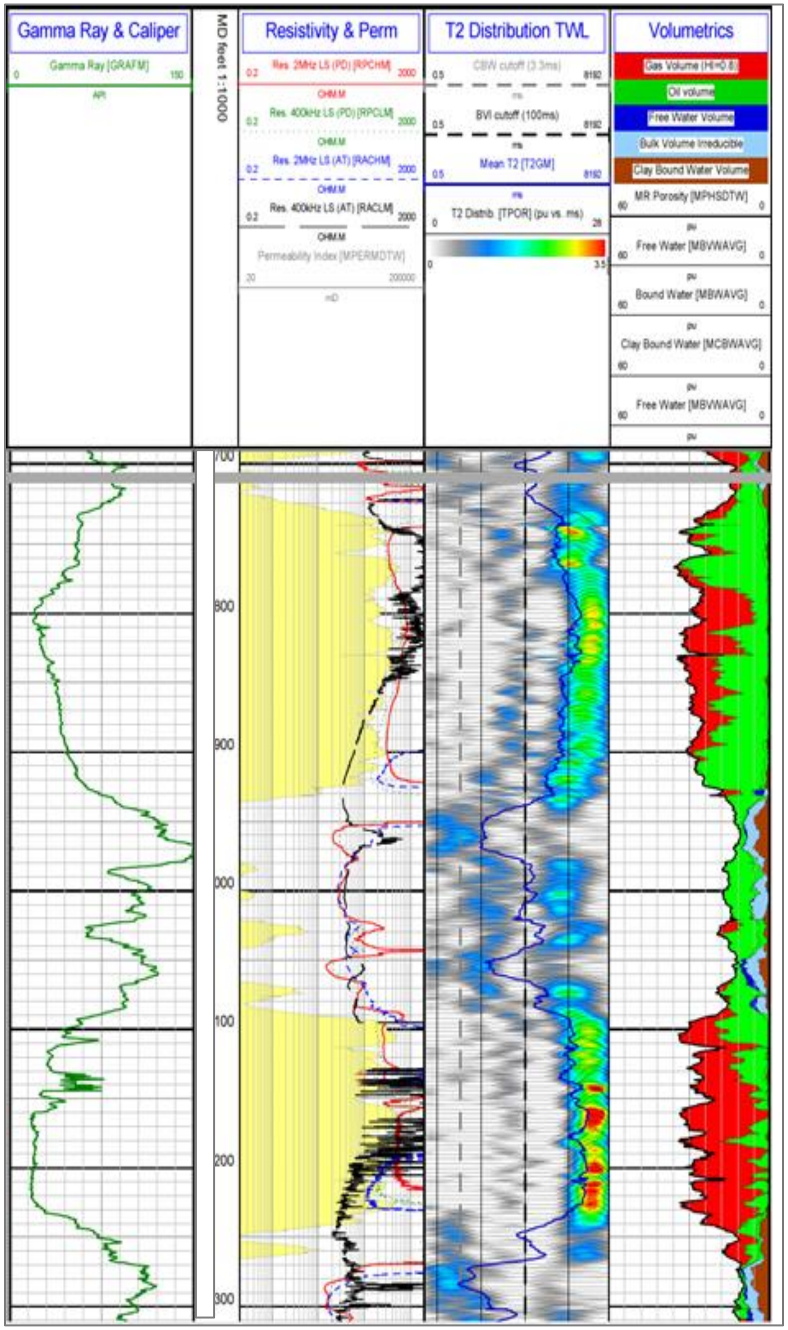

Figure 5b. Dual wait time hydrogen index correction for gas and oil-based mud filtrate. The gas is shaded red while the oil-based mud filtrate is shaded green, on the last track.

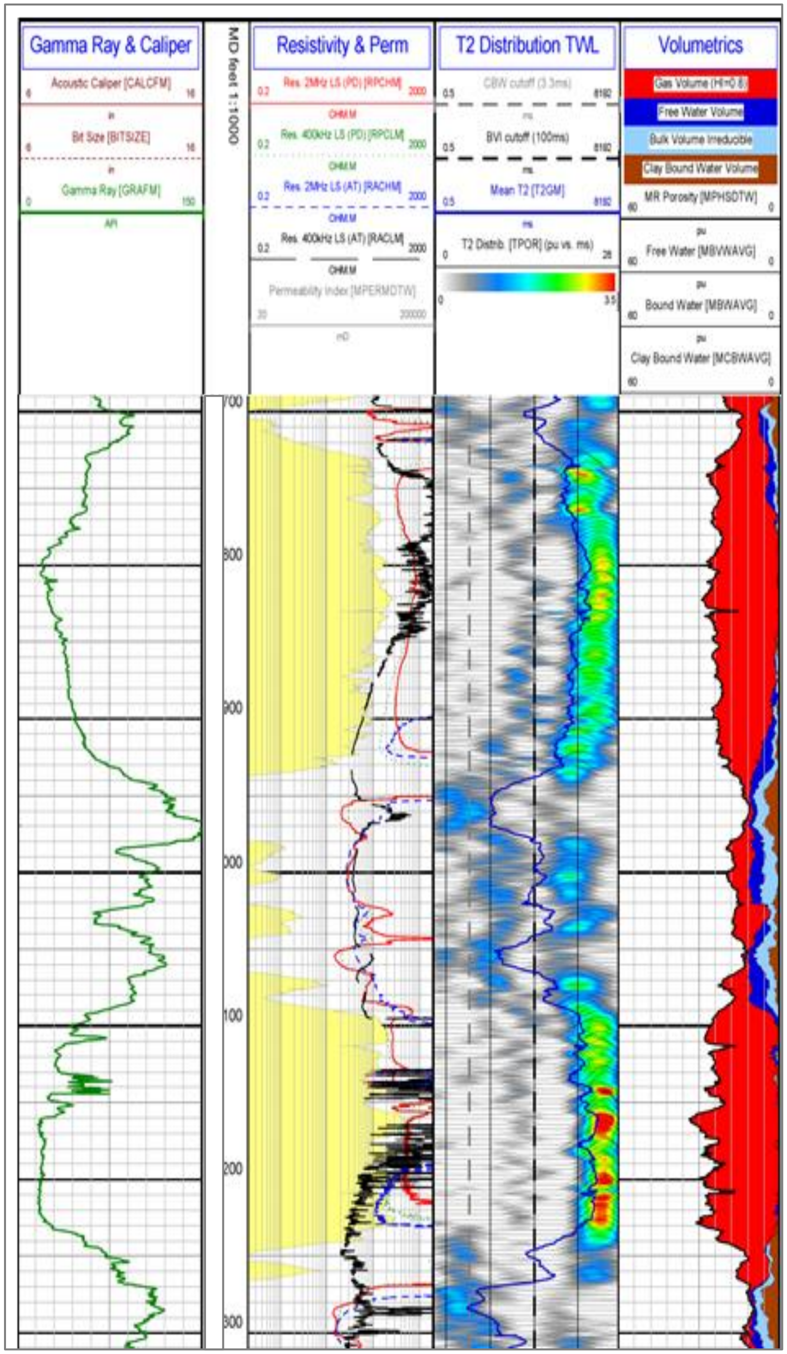

Figure 5c. Dual wait time hydrogen index correction for gas only. The result shows a corrected total porosity of 24pu for the gas.

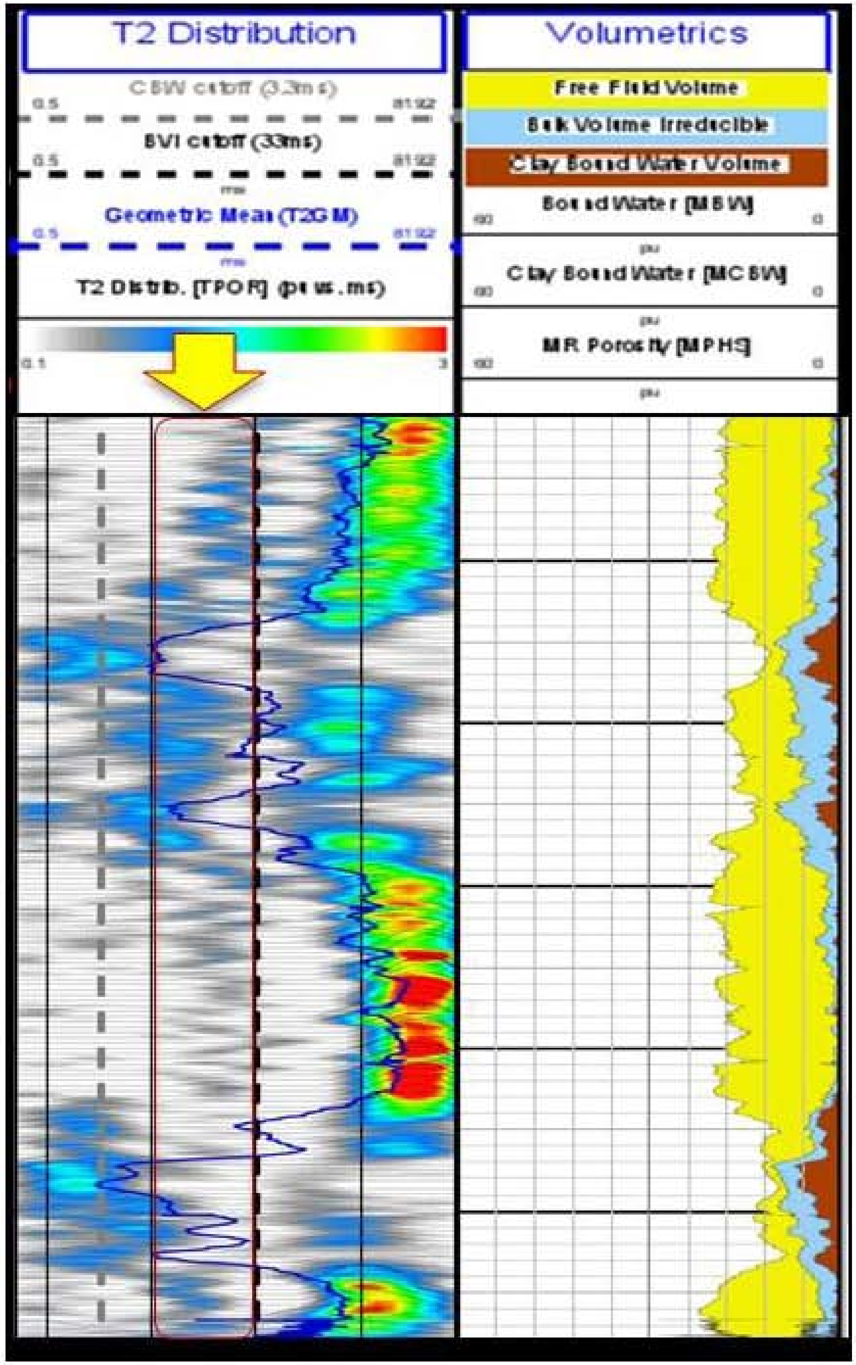

Figure 6. Increase in irreducible water T_2 cut-off as a result of oil-based mud filtrate invasion. BVI cut-off is adjusted from 33ms to 100ms.

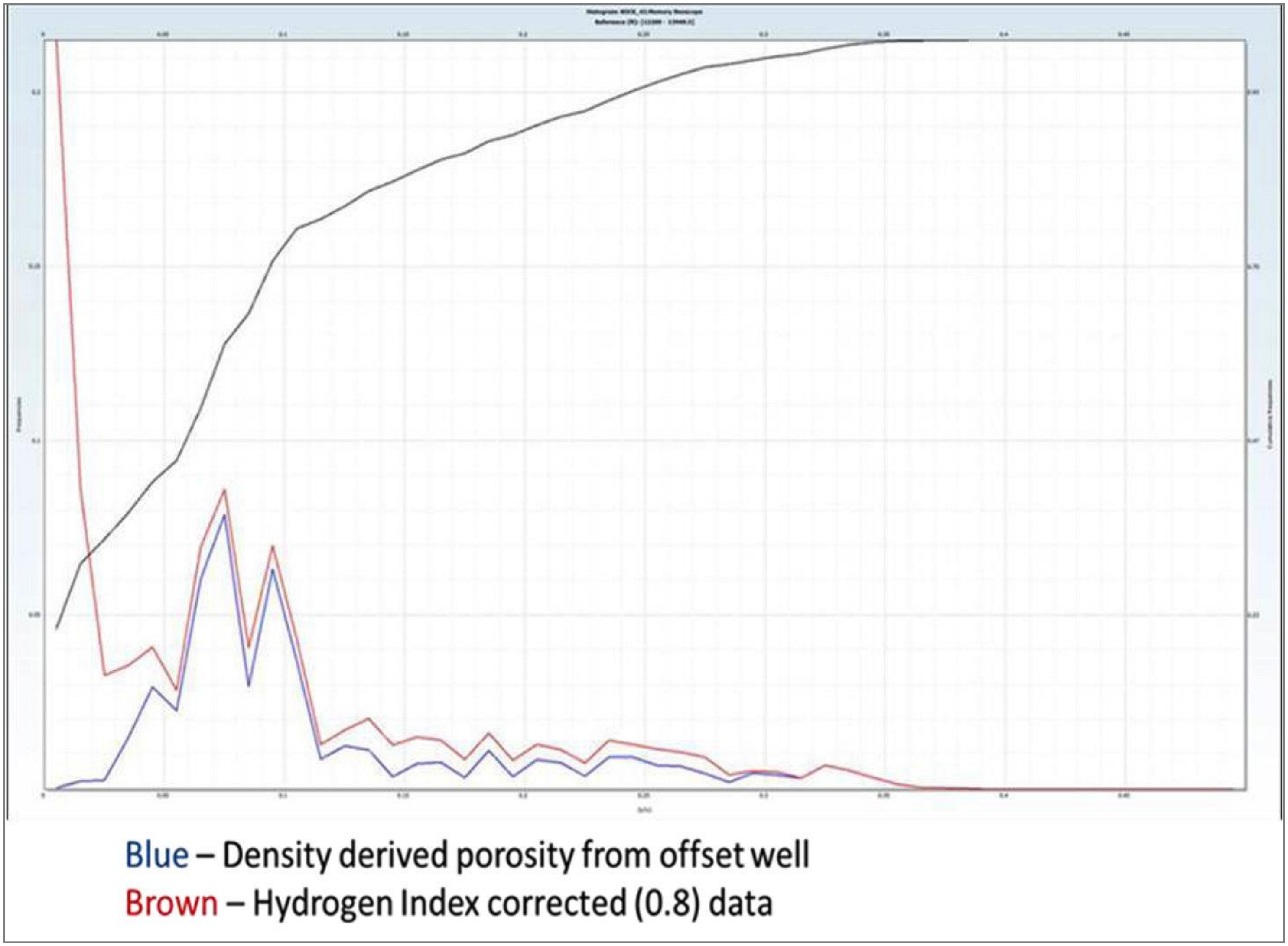

Figure 7. Comparison of dual wait time hydrogen index-corrected porosity and density porosity from offset well. This shows a perfect match.