SIMULTANEOUS RESERVOIR PERMEABILITY AND FLUID VISCOSITY ESTIMATION FROM NMR IN CASE OF VARIABLE VISCOUS OIL PROPERTIES

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ABSTRACT

The dynamical evaluation of shallow, high permeability, clastic reservoirs filled with a heterogeneous, high viscosity oil is a really challenging task: in order to accurately propagate core permeability data, the multi-darcy drains require to finely capture the vertical reservoir heterogeneity through a continuous proxy log sensitive to the formation dynamical properties. NMR can be an effective solution provided that the oil viscosity signal is accurately deconvolved, precisely in case of heterogeneous heavy fluids.

This paper presents a field case where the conventional 1D NMR interpretation technique based on cut-off failed and had to be fully revised. The viscosity of the fluid ranges from 40 to 200 cP and varies laterally and vertically, thus leading to a NMR bulk signal mixed to the clay bound water on the one hand and the capillary bound water on the other hand. The classical cut-off technique is consequently totally ineffective and required developing a fit-for-purpose approach based on the deconvolution of simulated fluid signatures directly in the raw echoes decay domain.

The oil signal, once extracted, was observed to be complex and mainly composed of two contributing elements of different behaviors: the bulk fluid signal, constant and homogeneous over the field, and a tiny heavy end signal in the low T2 domain, variable and geographically distributed. Such a behavior was further confirmed by dedicated laboratory NMR experiments and, at field scale, from a synthesis study on samples viscosity. This led to a new correlation for estimating viscosity in case of complex fluids based on a new NMR oil peak attribute. The latter could be correlated at field scale and led to an effective vertical and geographical understanding of the fluid behavior and equilibrium.

Finally, the approach proposes a way to correct the classical NMR derived mobility based on T2 logarithmic mean from the oil viscosity. It consists in calibrating the NMR permeability in water zones and applying a correction factor taking into account the drift caused by the oil viscosity. The final products, i.e. formation permeability and oil viscosity, were both compared to independent references, such as the permeability modeling from logs and core data, DST interpretation results and oil viscosity model based on sample data. The NMR results revealed to be at least of equal quality as the reference approaches and, in some cases, locally more accurate.

The added value of this purely NMR based approach is to deliver permeability and viscosity in a consistent manner, both at the same vertical scale. It gives the NMR log an effective added value for field understanding in terms of dynamical behavior and fluid properties distribution. It also helps interpolating both sample and core data and fine-tuning local heterogeneities that were not necessarily captured initially. Finally, it delivers a further validation of the heavy fluid signature in the T2 domain that opens perspectives for the NMR technique to be used for fluid characterization.

INTRODUCTION

The detailed understanding of field dynamics requires the integration of a large spectrum of techniques ranging from reservoir geology to thermodynamics, petrophysics and production. This becomes even more challenging when the field is compartmentalized and heterogeneous. In such a context, any dynamical measurement (direct or even indirect) has a value and should play a role in the integration process of the reservoir study. This paper illustrates how the NMR log has been combined and integrated to a field study by different ways to understand the fluids distribution (in conjunction with the fluid samples synthesis),
the permeability estimation (combining core data and permeability modeling) and the field dynamical behavior (thanks to permeability upscaling and production tests). At each level, the NMR log provided an added value on its own and played, in parallel, the role of integration platform.

The application case is an onshore field composed of shallow (350-650 m burial) Plio-Miocene unconsolidated fluvi-lacustrine sands (lacustrine delta-front) with thin inter-bedded claystones. The system appears heterogeneous at all scales:

- A large variety of lacustrine facies alternate rapidly, leading to a broad range of petrophysical properties (Porosity: 25 to 45%, permeability: 100 mD to 70 D) over few meters, including multi-darcy drains of the highest interest;
- The structure itself is composed, at field scale, of 5 panels with 4 main reservoir layers with very variable continuity. This translates into 5 static fluid pools that do not correspond to the panels.

The fluid appears also very heterogeneous. The system is made of a 145 m thick oil column topped by a 90 m gas cap. The oil has been sampled extensively over the field (14 samples) and at regional scale (26 samples). A thermodynamic synthesis comes to the following average picture: downhole live density of 890 kg/m$^3$, $R_s$ at 70 Scf/Bbl and viscosity ranging between 40 to 220 cP for average reservoir conditions of 45 bar and 55°C. The high oil viscosity is mainly due to the important bacterial biodegradation made possible by the low reservoir temperature and a large oil/water contact area over the structure. This, combined with the field connectivity, panel by panel, leads to a complex and heterogeneous fluid dynamical properties distribution.

To capture and characterize the different levels of heterogeneity in the field, a systematic acquisition has been launched for the 5 appraisal wells of the structure:

- Conventional log acquisition in water based mud (GR, DENS, NEUT, Resistivities, DTP, DTS) plus systematic NMR (T2 mode)
- 48 cores for a total cumulated length of 175 m over 5 wells, 179 core plugs
- 9 production tests

Despite this complete dataset, no petrophysical log from the core plugs could be constructed because of the extreme facies variability and the lack of mini-permeability log due to cores un-consolidation. Consequently, the multi-scale reconciliation between core and tests requires an independent dynamical continuous proxy to finely propagate data, understand the exact contribution of each facies and capture the vertical reservoir heterogeneity. This proxy should also be sensitive to the extreme fluid variability to anticipate the balance between facies permeability and oil viscosity. For these reasons, NMR was run to answer all of these issues.

**LIMITS OF THE NMR INTERPRETATION TECHNIQUE WITH STATIC CUT-OFF**

In pure operational terms, all the NMR logs were of very good quality. However, from the interpretation point of view, after applying the classical cut-off method, clear issues appeared from well to well:

- (1) It was almost impossible to match saturations;
- (2) The NMR-derived permeability, even if calibrated on core, delivered an extreme dispersion;
- (3) The viscosity estimate was lower than expected and not correlated to measurements.

(1) Water saturation was estimated, on the one hand, from the Archie equation with clay correction based on Waxman-Smits formalism with the Juhasz method. All parameters were measured (water salinity, $m-n$ exponents, CEC) and the final result compared and adjusted on Pc-derived saturations. The final match was considered as robust with low residual uncertainty (± 4 su) – cf. Figure 1, red saturation curve. On the other hand, the irreducible saturation was deduced from NMR by applying a cut-off at 34 ms (calibrated in
laboratory with NMR experiments on water filled plugs); the result was a clear overestimation from NMR (cf. Figure 1, black saturation curve) by +5-10 su.

The resistivity derived saturation is fully calibrated by laboratory measurements (salinity, m\-n exponents, CEC), Pc-derived saturations from plugs are computed from the Free Water Level clearly observable on this well with low uncertainty in depth, the NMR saturation is derived from a laboratory measured cut-off at 34 ms (water filled samples)

All attempts to adjust the T2 cut-off between free and capillary bound fluids were unsuccessful and led to an unrealistic value of 6 ms with a very poor match to reference core saturation data. One interesting observation is the correlation of the saturation bias between Archie and NMR saturations with oil viscosity as displayed in Figure 2.

(2) The NMR irreducible saturation being suspicious, the Schlumberger-Doll-Research equation based on T2 log-mean [Kenyon (1988)] was preferred to Timur (1969) for the permeability estimation. This resulted in a difficult parameter adjustment for a very disappointing final match with core data– cf. Figure 3.
(3) The NMR viscosity was estimated using the correlation from Lo (2000) based on the T2 log-mean (T2LM). To avoid any effect of the clay bound signal on the T2LM, a dedicated extraction of the free fluid T2 mode was performed. The viscosity result was then compared to the measurements on PVT samples (Figure 4) and revealed to systematically underestimate the oil viscosity by a factor of 2 (40 cP instead of 80-100 cP) and to ignore completely the oil variability.

**SIGNAL PROCESSING AND HYDROCARBON SPECTRUM EXTRACTION**

The NMR spectra over 3 reference intervals have been stacked, extracted and displayed in Figure 5:

![Figure 5 - NMR spectra for 3 reference intervals: Shale, Oil and Water zones](image)

**Figure 5 -** NMR spectra for 3 reference intervals: Shale, Oil and Water zones

The shale interval is a thick massive shale layer with homogeneous and stable NMR signal. The water bearing zone is a representative thick homogeneous sand layer, clay-free, and 100% water bearing. Same for the oil bearing interval fully oil saturated up to irreducible.

From the comparison of these 3 spectra, it results that:

- **Water interval**: the classical 33 ms cut-off is well adapted to separate free water from capillary bound. The cut-off is further confirmed by laboratory experiments (34 ms) and irreducible water saturation reconciliation with Pc-drainage curves;

- **Oil interval**: The NMR signal in oil bearing zones is composite and made of 3 contributions. At high T2 (T2 > 350 ms), the signal is dominated by the water based mud filtrate contribution. For T2 lower than 300 ms, lab experiments have shown that the rest of the signal is due to oil.

The oil signal appears complex, multi-modal, located around 33 ms and overlays, on the one hand, the capillary-bound water peak and, on the other hand, the shale signal. This explains why the cut-off interpretation technique failed to deliver consistent irreducible water saturations.
In order to better understand the oil NMR signature, it comes that the bulk T2 spectra need to be decomposed in independent fluid contributions as proposed by Freedman (2001). This becomes even more important for intermediate/mixed signatures. But a peak adjustment in the T2 domain would not bring any extra added value as it would simply mimic the inversion result. The approach we propose is a peak adjustment in the echo space domain that consists in 6 steps:

- Create a basis of T2 spectra (called $F_j^*_{ref}$) from reference intervals for shale and water – Eq. 1;
- Decompose the oil signal into 3 contributions, fitted by log-normal laws (named below $F_j$) – Eq. 2;
- Generate the echo-decay signal $M_p$ from this basis using the same kernel $K_i$ as for inversion – Eq. 3, Eq. 4 and Eq. 5;
- Minimize the difference between real echoes amplitudes $E_p$ and the simulated ones $M_p$ by optimizing the $A_j$ amplitudes and/or the peaks attributes ($\mu_j$ and $\sigma_j$) – Eq. 6;

The processing sequence is written below:

\[
F_j(T2_i) = A_j \cdot F_j^*_{ref}(T2_i)
\]

\[
F_j(T2_i) = \frac{A_j}{\sigma_j \sqrt{2\pi}} e^{-\frac{1}{2} \left( \frac{ln(T2_i) - \mu_j}{\sigma_j} \right)^2}
\]

\[
F(T2) = \sum_j F_j(T2_i)
\]

\[
K_i(WT, t_p) = \left(1 - e^{-\frac{WT}{t_p}}\right) \cdot e^{-\frac{t_p}{T2_i}}
\]

\[
M_p = \sum_i K_i(WT, t_p) \times F(T2_i)
\]

\[
\min_{A_j, \mu_j, \sigma_j} \sum_p w_p \left( \frac{E_p - M_p}{\Delta_p} \right)^2
\]

\[
w_p = H(T2_R - t_p) \cdot H(t_p - T2_L)
\]

\[
\chi_{model} < \chi_{inversion}
\]

The optimization process consists in minimizing the differences between the modeled echoes amplitudes $M_p$ and the real NMR measurements $E_p$. This difference is however weighted by the initial inversion residue $\Delta_p$ to mitigate the impact of outlier echoes and preserve the same level of regularization. The optimization is not done in one shot but in a sequence with variable windows $w_p$. Such windows are defined in Eq. 7 ($H$ being the Heaviside function); the process consists in adjusting the fit with echo amplitudes iteratively for different ranges of T2 ($T2^L$ and $T2^R$ stands for left and right T2 limits, respectively), the result of one fit being fixed and re-used for the next interval. The basic idea is to work successively with T2 intervals which borders ($T2^L$ and $T2^R$) minimize the signal overlay. The optimization is then done for each contribution $F_j$ one by one; we generally start with a first window centered on the shale signal (0.3 – 10 ms), then the free fluid within 100 – 3000 ms (fitted with either the water or filtrate signals based on log interpretation criteria) to finish with the 10 – 100 ms domain. For each window, the reference signals $F_j^*_{ref}$ are tested first (with $A_j$ optimization) and extra peaks are added one by one only if the echo amplitude reconstruction residue $\chi$ does not honor the condition in Eq. 8. For each window, only peaks allowed to overlay one another from Figure 5 are tested and the selection is made based on log interpretation results (presence of shale, presence of oil, presence of movable water...). In the end, the final model over all the windows is tested once more with Eq. 8.

The final result consists in the decomposition of the T2 spectrum with a minimum number of components in parallel to the resulting simulated echo amplitude decay – cf. Figure 6 and Figure 7.

![Figure 6 - T2 spectrum decomposition result](image-url)

*Solid bold blue line: T2 spectrum; thin green solid line: shale signal; thin blue solid line: oil signal; thin black line: water base mud filtrate signal; red circles: simulated overall spectrum after optimization.*
Figure 7 - Echo train simulation vs. measurement

Red bold solid line: simulated echo train ($M_p$); Thin blue solid line: raw echoes ($E_p$);

This approach proved to be effective over the whole range of clay content:
- Reservoir with 20% shale and a bimodal oil signal – Figure 8 (a);
- Reservoir with 50% shale and a bimodal oil signal – Figure 8 (b);
- Reservoir, 70% shale, with a weak bimodal oil signature – Figure 8 (c).

Figure 8 - T2 spectra decomposition by optimized components

Solid blue line: oil signal; Dashed green line: heavy oil signal; Thin solid green line: shale signal; Solid black line: water base mud filtrate signal; Bold colored lines: T2 spectra; Red circles: simulated spectrum after optimization.

This processing was used to extract a pure oil signal envelope at every depth. This latter is composed of a maximum of two independent components for which amplitudes $A_j$, locations $\mu_j$ and sizes $\sigma_j$ were kept free during the optimization. An example of hydrocarbon spectrum extracted from Figure 8 / case (b) is illustrated in Figure 9:

Figure 9 - Oil signal extraction from ambiguous NMR spectrum

NMR T2 spectrum (top) and corresponding oil signal extraction result (bottom brown) decomposed in elementary contributions – dashed green: heavy oil signal, solid blue line: oil signal.
The final delivery of this processing is the decomposition at every depth of the full spectrum from which a detailed analysis of the oil signal can be drawn independently from any petrophysical artifact.

**OIL T2 SPECTRUM AND VIScosity CORRELATION**

In order to validate the oil signal processed from NMR logs, a dedicated laboratory acquisition has been performed on bulk oil samples. These were all selected from different wells within the same reservoir unit and with the lowest contamination level possible. The objective was to cover the largest range of viscosity. As the live fluid has quite a low GOR (~70 Scf/Bbl), all the experiments were performed on dead oil at reservoir temperature (30°C) on a 2 MHz system with 200 µs inter-echo spacing. The lab echoes were processed with an inversion software analogue to the one used for wireline data (in-house developed from Venkataramanan (2002)). For a comparison purpose, the T2 spectra were normalized. The results on 4 samples are displayed in Figure 10.

![Figure 10](image)

**Figure 10** - Laboratory NMR spectra on 4 oil samples

The corresponding 4 oil signatures from NMR logs are displayed in Figure 11. Despite the fact that the overall spectrum shape is slightly different because of different inter-echo time, signal-to-noise ratio, regularization and the use of a log-normal basis for oil extraction, some clear observations can be drawn:

- The 4 oils display the same maximum amplitude T2, independently from their viscosity;
- Most of the variability between the spectra is on the low T2 side with a clear distribution asymmetry proportional to oil viscosity: the higher the viscosity, the more the spectrum spreads to low T2.

These observations find an explanation in the oil behavior and the field context. The system is indeed composed of a primary oil charge with moderate viscosity (~40 – 50 cP) that corresponds to the main NMR peak around 40 ms. This first fluid contribution is homogeneously distributed over the field and constitutes the native oil. However, a thorough geochemical samples synthesis proved that this charge may locally undergo an alteration by bacteria due to the cool temperatures of the field and the strong aquifer activity. This effect is a function of the distance to the water contact, layer by layer. The entire oil column then re-equilibrates from bottom to top. The biodegradation intensity is the main driver to viscosity and explains the variability observed over the field.

In terms of NMR, the biological effect consists in degrading the light paraffinic chains of the fluid that, in return, concentrates the complex and heavy remaining components. NMR, being sensitive to the free molecular rotation ability...
of the medium (cf. Mutina (2008)), consequently, deviates to the low T2 domain as observed by Seccombe (2005) and characterized by Kurup (2013) and Korb (2013). The intensity of biodegradation then controls the amplitude of the secondary NMR peak in the low T2 domain. But, as the biodegradation does only partially alter the oil – the process is still ongoing –, the native oil signature is still partially preserved. This leads to the bimodal NMR oil signature with a fixed main peak and a variable secondary signal. This explains why the approach based on T2LM failed in estimating oil viscosity; as the biodegradation peak represents only a tiny fraction of the NMR signal, sometimes hidden by clay and capillary bound water, the logarithmic mean of T2 is mainly driven by the native oil T2 contribution. Any viscosity estimate from T2LM is consequently a sort of evaluation of the native charge viscosity: it never exceeds 40 cP and is homogeneously distributed over the field.

The effective oil viscosity estimation with NMR requires the use of another attribute than T2LM. Viscosity, being controlled by the intensity of biodegradation, signs by a secondary peak in the low T2 domain. We then propose to correlate to viscosity the T2 distance between the mode of the oil peak and the left intercept at 20% of the normalized amplitude; this quantity is called \( \Delta T2 \) (ms) – cf. Figure 12.

![Figure 12 - \( \Delta T2 \) attribute definition](image)

The \( \Delta T2 \) attribute is defined as the T2 time distance in milliseconds between the abscissa of the mode of the oil peak (generally close to 40 ms) and the left intercept at 20% of the normalized amplitude.

The test has been performed for both laboratory NMR experiments and log data as plotted in Figure 13.

![Figure 13 - Left T2 intercept at 20% of normalized spectrum amplitude versus downhole oil viscosity](image)

The two datasets display a correlation between the live oil viscosity (downhole conditions) and the \( \Delta T2 \) attribute; in both cases, the higher the viscosity, the broader the oil T2 peak is. Besides the two correlations display almost the same general shape, they are not exactly the same. The difference is mostly an offset of few milliseconds in \( \Delta T2 \) due to the difference of acquisition and processing between laboratory and log data (inter-echo spacing, signal-to-noise ratio, regularization, stacking and oil peak extraction procedure). However, the two behaviors can be considered as equivalent and quantitatively meaningful. The datasets have been interpolated with the following polynomial form (Eq. 9):

\[
\Delta T2 = \sum_k a_k \cdot \eta^k
\]

Table 1 gathers the coefficients of the two correlations.

<table>
<thead>
<tr>
<th></th>
<th>Lab correlation</th>
<th>Log correlation</th>
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</thead>
<tbody>
<tr>
<td>( a_2 \times 10^{-4} )</td>
<td>2.20</td>
<td>2.67</td>
</tr>
<tr>
<td>( a_1 \times 10^{-2} )</td>
<td>-2.02</td>
<td>-2.31</td>
</tr>
<tr>
<td>( a_0 )</td>
<td>41.84</td>
<td>40.92</td>
</tr>
</tbody>
</table>

Table 1 - \( \Delta T2 \)-Viscosity correlation coefficients
The quantitative correlation between NMR and oil viscosity defined above has been proven to be valid and applicable only over the reservoir layer used as training interval. The approach has now to be validated and extended at a larger scale for the entire field and all the reservoir layers.

**OIL VISCOSITY FROM NMR LOG AND PERMEABILITY CORRECTION**

All the valid available oil samples of the database (16) have been plotted versus their corresponding NMR log signal (after oil peaks extraction and $\Delta T2$ computation). They are displayed regardless of their layer and well location in Figure 14. The correlation defined in Figure 13 is also displayed and translated for various $a_0$ and $\eta_0$ offsets (as depicted in Eq. 10).

\[ \Delta T2 = \sum_k a_k \cdot (\eta - \eta_0)^k \]

**Figure 14** - Viscosity versus log based $\Delta T2$ for the 16 oil samples of the database

*Point: oil sample with laboratory viscosity as Y and log based $\Delta T2$ as X; Color: well; Dashed gray lines: iso-viscosity/$\Delta T2$ lines for various $a_0$ and $\eta_0$ offsets.*

The viscosity data points over the field are too sparse to formally validate the viscosity correlation; nevertheless, their distribution in the viscosity-$\Delta T2$ domain is globally compliant with the model. In addition, even if not organized by well, they do follow the law, reservoir unit by reservoir unit, for a given set of $a_0$ and $\eta_0$. It comes that each fluid unit behaves on its own at field scale but respects globally the same viscosity law. To investigate and understand the driving factors leading to such a behavior, the $\Delta T2$ attribute has been displayed versus different parameters: the vertical distance to Gas-Oil Contacts (GOC) in Figure 15 and, in Figure 16, versus the predicted viscosity from thermodynamic model after projecting the $\Delta T2$ on an arbitrary reference datum.

**Figure 15** - Vertical distance to GOC versus the $\Delta T2$ from log NMR for all the wells

**Figure 16** - Viscosity of the thermodynamic fluid model versus $\Delta T2$ from NMR log after projection on a reference datum

*For both graphs, the colors are related to the reservoir units. The viscosity is a continuous log derived from the thermodynamic model based on sample data only. The $\Delta T2$ is defined as explained in Figure 12 but, for practical reason, expressed in bin instead of millisecond.*
For a given reservoir unit, the $\Delta T_2$ log attribute shows a vertical drift from the GOC reference depth (solid red arrow in Figure 15). This effect is the translation of the vertical fluid column re-equilibration submitted to bacterial activity at WOC. Surprisingly, the trends are better organized when plotted versus GOC than WOC depths. This is explained by the possible WOC change through time due to structural control and active hydrocarbon migration, the bacterial activity then being transferred vertically. On the other hand, the GOC location is a direct indicator of the biodegradation intensity; the gas produced by bacteria at WOC strips the oil column, accumulates in the gas cap and moves the GOC.

However, in addition to the vertical drift, a second offset clearly affects $\Delta T_2$ (parallel colored lines in Figure 15 and red empty arrow). In order to normalize the data and compare signatures, $\Delta T_2$ has been vertically projected on an arbitrary datum; the new indicator can be used as if all reservoir layers were at the same vertical distance to the GOC – cf. Figure 16. It comes that the shift in data is different for each reservoir layer (data points color). To understand the driving factor behind the data organization, the sub-dataset for each reservoir unit has been linearly interpolated. All lines have been constrained with the same slope but variable offsets (cf. colored lines in Figure 16). These offsets then have been plotted versus various attributes of the field and the best correlation appears with the horizontal distance between the reservoir interval at well path and the GOC – cf. Figure 17. This correlation, as for the vertical drift, confirms the driving role of biodegradation and the geometrical control played by the structure on the fluid column re-equilibration, this being either vertical or lateral. In a sense, the field system behaves homogeneously thanks to powerful equilibration processes supported by efficient lateral and vertical communications along each reservoir unit. These, however, starting from the same original fluid charge, behave independently under the driving factor of biodegradation. The distribution of the fluid properties is then closely linked to the intensity of the bacterial effect as probed by the NMR log.

Figure 17 - Lateral distance to GOC versus $\Delta T_2$-Viscosity offsets

The above observations lead to a calibration of the $\Delta T_2$-viscosity correlation (Eq. 10) with corrective terms that take into account the vertical equilibrium, its structural control and the biodegradation intensity. The correlation then becomes:

$$
\Delta T_2 = \sum_k a_k (\eta - \eta_0)^k
\frac{1}{a_0} = b_0 + b_1 Z_{GOC} \\
\eta_0 = c_0 + c_1 d_{GOC}
$$

$Z_{GOC}$ [m] and $d_{GOC}$ [m] are, respectively, the vertical distance and the lateral distance to the GOC. The $a_k$, $b_k$ and $c_k$ coefficients are specific to the field. They have been calibrated and results are in Table 2:

<table>
<thead>
<tr>
<th>Coefficient</th>
<th>Value</th>
<th>Unit</th>
</tr>
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<tbody>
<tr>
<td>$a_1$</td>
<td>-2.31\times10^{-4}</td>
<td>ms.cP^{-1}</td>
</tr>
<tr>
<td>$a_2$</td>
<td>2.67\times10^{-2}</td>
<td>ms.cP^{-2}</td>
</tr>
<tr>
<td>$b_0$</td>
<td>0.452</td>
<td>ms^{-1}</td>
</tr>
<tr>
<td>$b_1$</td>
<td>2.65\times10^{-3}</td>
<td>ms^{-1}.m^{-1}</td>
</tr>
<tr>
<td>$c_0$</td>
<td>-1.89</td>
<td>cP</td>
</tr>
<tr>
<td>$c_1$</td>
<td>5.02\times10^{-2}</td>
<td>cP.m^{-1}</td>
</tr>
</tbody>
</table>

Table 2 - Viscosity correlation coefficients
From now, a viscosity model at field scale, fully calibrated, can predict viscosity from the NMR log. In order to evaluate the prediction robustness of such equations, a comparison with the reference thermodynamic model has been attempted and is presented in Figure 18. The test covers a wide range of viscosities for all the reservoir layers of the field logged with NMR; a blind test has also been performed on a satellite structure that has not been used to build the model (yellow colored points).

The overall behavior of the model is fair and delivers viscosity estimations within ±5 cP at 40 cP up to ±20 cP at 200 cP, leading to a relative maximum uncertainty around ±10%. This may appear large but remains acceptable for the viscosity domain of this field (40-220 cP). One should also take into consideration that the NMR derived viscosity has been compared to a thermodynamic model built on sample data of variable qualities and contamination levels. One good point of the NMR approach is to propose a continuous proxy for the oil viscosity along reservoir sections while samples deliver only a discontinuous set of measurements that require strong hypotheses in terms of reservoir connectivity for vertical propagation. Finally, it is worth noting that the model could deliver good viscosity prediction even outside its calibration domain for an equivalent residual uncertainty.

Once the viscosity model defined, the next step consists in the permeability estimation. The principle of the approach is to, first, calibrate the NMR permeability equations in water zones and, second, define a viscosity correction for oil intervals.

In order to use the same permeability formalism for oil and water zones and because the irreducible saturation from NMR is hampered by the oil signal, a pseudo-SDR approach was preferred (adapted from Kenyon (1988)). The equations exponents have been calibrated on core data as displayed in Figure 19.

The resulting correlation is provided in Eq. 12 (for $K$ in mD and T2LM in ms) with coefficients listed in Table 3.

$$\log K^* = \sum_n e_n \cdot (\log T2LM)^n$$
Table 3 - Permeability correlation law coefficients

<table>
<thead>
<tr>
<th>$e_n$</th>
<th>Value</th>
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<tbody>
<tr>
<td>$e_0$</td>
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<td>8.17</td>
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</tr>
<tr>
<td>$e_3$</td>
<td>0.75</td>
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The final result from NMR is slightly less vertically resolved than the MRGC curve that uses density. Conversely, the NMR better solves the permeability estimation in shales for which the MRGC had to extrapolate a result with no core constraint.

The transposition of the permeability estimation to oil bearing reservoirs requires understanding how the NMR spectrum is composed. When oil is present, the T2 distribution is dominated by the hydrocarbon light end peak (the native charge). The capillary bound water and the water base mud filtrate have only minor contributions and generally disappear behind the main peaks. This also occurs for the oil heavy end that, however, plays a significant role in the oil viscosity. Consequently, any bulk T2LM approach would deliver a sort of mobility indicator dominated only by the viscosity of the light end of the oil. In order to redress such an estimation, the result has to be normalized and rescaled with the effective oil viscosity as formalized in Eq. 13:

$$K = K^* (T2LM) \times \frac{\eta(\Delta T2, GOC, \Delta GOC)}{\eta(T2LM, GOR, T)}$$

Where:
- $K^*$ is a mobility indicator obtained from Eq. 12 [mD] in oil interval;
- $\eta$ is the effective oil viscosity derived from Eq. 11 [cP];
- $\eta^*$ is the apparent viscosity of the light end of the oil estimated from Lo (2000) and expressed in cP.

The resulting permeability is supposed to be viscosity-free, calibrated on core plugs and sample data, and based only on NMR, hence independent from any other log.

MULTIPLE SCALES PERMEABILITY VALIDATION AND RESULTS DISCUSSION

The NMR derived permeability has now to be confronted to calibration points at multiple scales: core plug and test scales. Note that core plugs have been used within water zones only: the comparison over oil bearing intervals is a real independent blind test. Same for DST permeabilities that have never been used in the computation process.
When comparing any permeability curve to core plugs, the plug representativeness may create a bias. The NMR derived permeability was then deliberately plotted systematically with the smoothed core supervised MRGC result (KRES_SMO) as baseline reference – cf. Figure 21 and Figure 22.

The difference between the two permeability estimations ranges within a decade. The drift is almost zero for high permeabilities but increases below 2000 mD where the MRGC prediction is slightly more scattered contrary to the NMR’s (Figure 21). This behavior is exactly the same as for the water zone calibration except that, in oil intervals, the MRGC tends to underestimate permeability instead of overestimating it. This behavior probably exists all over the permeability scale but becomes sensible only at low values. This could be related to a fluid bias on the MRGC method with partial hydrocarbon pre-correction on logs. In a word, NMR is able to deliver a unbiased permeability estimation over the whole scale, fully corrected from fluid effect, that fits both core data and the estimate at log scale from the MRGC reference technique.

A further validation is provided by the comparison with DST results. The objective is to test the ability of the NMR permeability to be up-scaled. The results of this test are also compared to the MRGC to evaluate the added value of the NMR technique. For that, a thorough program of tests has been interpreted to provide reference, large scale, permeabilities over production intervals. The comparison is illustrated in Figure 23.

**Figure 21** – Permeability estimations from NMR (red) and smoothed supervised MRGC (green) versus core plug references

**Figure 22** – Histogram of the logarithm difference between smoothed supervised MRGC (KRES_SMO) and NMR-derived (KNMR) permeabilities

**Figure 23** - Comparison of NMR, MRGC and DST derived permeabilities
The study case presented in this paper shows the large potential of the NMR data in the formation evaluation process, from the volumetric (bound and free fluid volumes) to the dynamical parameters estimation (such as viscosity and permeability). The challenge consists in identifying the different contributions in the NMR spectrum and being able to deconvolve each of them. The 2D techniques in the T1-T2 or D-T2 domains are effective solutions that were not available in this study. Even though, the use of laboratory results in bulk, confined and D-T2 were key for a clear fluid signature understanding. It appeared, in this case, that the oil signal is complex and composed of multiple contributions that sign and quantify the different geochemical processes that occurred at field scale. NMR was able to probe and resolve them accurately. Any further improvement in the low T2 domain of the logging tools would, for sure, lead to even better signal and more accurate heavy oil characterization as observed in laboratory conditions.

More than a simple oil signal measurement, the NMR log provides a precise continuous and quantitative proxy to probe reservoir dynamics at log scale in a consistent manner. This can play a role in extrapolating fluid sample data, optimizing the sampling program and understanding the reservoir compartmentalization. NMR proved also to be compatible at all scales with dynamical constraints from core plugs, smoothed log-derived permeability and DST tests. The results then played a role in the fine identification and characterization of local reservoir heterogeneities. In a sense, NMR delivers its maximum potential when integrated extensively to all the dimensions of the reservoir synthesis.

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NOMENCLATURE

T2 Transverse relaxation time [ms]
σ the (T2) standard deviation [ms]
μ log(T2) average [ms]
F T2 fractional contribution [-]
WT Polarization duration, waiting time [ms]
tp Echo measurement time [ms]
Ki NMR kernel [-]
Ep Measured echo amplitude [-]
Mp Computed echo amplitude [-]
Δ p = (Ep - Mp) from NMR inversion [-]
w Weighting factor [-]
χ Inversion residue (cf. Eq. 6) [-]
GOR Gas-to-Oil ratio [Scf/Bbl]
T2LM T2 logarithmic mean [ms]
ΔT2 T2 difference [ms]
η Oil viscosity [cP]
Ak, ak, bk, ck, ek Coefficients [-]
T Formation temperature [°C]
Z Vertical distance to GOC [m]
dGOC Horizontal distance to GOC [m]
K Permeability [mD]

Constants
π = 3.14159… (π constant)
e = 2.71828… (Euler’s constant)
ξ T1/T2 ratio, constant ~ 1 for heavy oil

Subscripts
i, j, k, n

Functions
Heaviside function: H(x<0) = 0, H(x≥0) = 1
log() logarithm in base 10

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Simultaneous Reservoir Permeability and Fluid Viscosity from NMR in Case of Variable Viscous Oil Properties

E. Caroli, C. Lafaurie, C. Duval, B. Nicot, N. Vorapalawut, M. Bueno, TOTAL

Paper #148
### The problem...

#### Viscosity variability from sampling

<table>
<thead>
<tr>
<th>Well</th>
<th>GR</th>
<th>Density Neutron</th>
<th>NMR</th>
<th>Volumes</th>
<th>Satur.</th>
</tr>
</thead>
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<td>1</td>
<td></td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>0</td>
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</tr>
</tbody>
</table>

#### Viscosity variability from NMR $T_{2LM}$

- Resistivity derived **SW**
- NMR-derived irreducible **SW**
- Pc-derived irreducible **SW**

Well1 Well2 Well3 Well4 Well5
Content

1. Hydrocarbon Signal Extraction from NMR Log

2. Viscosity Signature in Hydrocarbon NMR Signal

3. Viscosity Correction to Permeability Correlation
1 Hydrocarbon Signal Extraction from Log NMR
3 Pure NMR Signals

The HC signal partly overlays with:
- Capillary bound water signal
- Clay bound water signal

The classical cut-off technique is not applicable as the HC signal is variable and overlays with water and clay

=> Dedicated processing to extract the HC signal
Inversion, Peak Fitting and Echo Simulation

1. Full NMR spectrum inversion

2. Peak fitting with reference signatures

3. Echoes simulation with sliding windows

4. Peak fitting optimization in the echo time domain

\[
\min_{A_j, \mu_j, \sigma_j} \frac{1}{2} \sum_p w_p \left( \frac{E_p - M_p}{\Delta_p} \right)^2
\]
Inversion, Peak Fitting and Echo Simulation

NMR spectrum decomposition

- Full NMR signal
- Inverted spectrum result
- Clay contribution
- Oil contribution #1
- Oil contribution #2
- Full Oil signal

Full NMR signal

Extracted hydrocarbon signal and contributions
Inversion, Peak Fitting and Echo Simulation

NMR spectrum decomposition

Depth #2

- Full NMR signal
- Inverted spectrum result
- Clay contribution
- OBM contribution
- Oil contribution #1
- Oil contribution #2
- Full Oil signal

Full NMR signal

Extracted hydrocarbon signal and contributions
Viscosity Signature in Hydrocarbon NMR Signal
• The $T_2$ mode does not vary with oil viscosity

• But the shape of the $T_2$ spectra signs the concentration of heavy paraffinic components, hence the fluid viscosity
Building a new viscosity proxy: \( \Delta T_2 \)

\[ \Delta T_2 \]

Normalized Amplitude [-]

T2 [ms]

- 105 cP
- 87 cP
- 84 cP
- 58 cP

20%
Asymmetry attribute and viscosity

\[ \Delta T_2 \text{ (ms)}@0.2 \]

from the HC NMR signal to be used as a proxy of viscosity
Validity test at field scale

Blind test: The $\Delta T_2$ correlation can explain all the sample viscosity points at field scale.

Viscosity is driven by the **distribution of the heavy end**, controlled at field scale by the **structure geometry** (viscosity shift) and the **oil column equilibrium** ($\Delta T_2$ offset).
• The viscosity model does **fairly fit the PVT model** on all the wells:
  ±5 cP @ 40 cP, up to ±20 cP @ 200 cP => ±10% relative

• The geometrical effect is enough to explain the viscosity distribution, leading to a quite **equilibrated fluid at the scale of the accumulation**
Viscosity Correction to Permeability Correlation
Permeability Modelling Strategy

Water zone

• Train the permeability in water zones: correlation between NMR and core perm

• Use the water correlation to compute the SDR mobility from NMR

• Compute the apparent HC viscosity with the NMR oil peak mode (VISCOA)

\[
\text{VISCOA} = f(T2\text{MAX}, \text{Temp}, \text{GOR})
\]

HC zone

• Compute the effective HC viscosity using the $\Delta T2$ model (VISCO)

• Redress the NMR-derived mobility by making a viscosity correction:

\[
K_{\text{oil}} = K_{\text{wat}} \times \frac{\text{VISCO}}{\text{VISCOA}}
\]
NMR-derived Permeability in Water Zone

\[ \log K = \sum_{i} a_i \cdot \log T2LM \]

<table>
<thead>
<tr>
<th>N-D</th>
<th>NMR</th>
<th>Poro</th>
<th>Perm mD</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>(10^{-1}) (10^{6})</td>
</tr>
</tbody>
</table>

[T2LM (ms) vs Core plug Kg (mD) graph]
NMR-derived Permeability in HC Zone

NMR permeability before viscosity correction

NMR permeability after viscosity correction

Permeability from log modeling

Test permeability

Interpolated and smoothed NMR viscosity

NMR predicted viscosity
Conclusion
Conclusion

• The classical approach (cut-off) failed => **NMR is dual** and contains both fluid and pore size signals

• In such a context, the petrophysics and fluid signals were mixed

• A fit-for-prupose approach permitted to:
  • Extract the HC NMR signal from other contributions
  • Train a predictive model from NMR to derive a continuous log of viscosity
  • Derive a viscosity-corrected permeability

• NMR revealed to be…
  – A good proxy for viscosity prediction **over the field**
  – Compatible, **at all scales**, to permeability measurements (core plugs, DST)
  – The only way to capture **in a continuous way** the field dynamical heterogeneities