Investigating NMR T2-Cutoffs: Towards better reservoir Characterization

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Abstract. This study focuses on the importance of accurately determining the T2 cutoff value, a crucial petrophysical parameter that differentiates movable fluid from immovable fluid in formations. Standard T2 cutoff values (33 ms for sandstones, 100/200 ms for carbonates) may not apply uniformly across a column, leading to discrepancies in saturation determination. Accurate T2 cutoff determination, typically done in the lab, is time-consuming and expensive. The goal of this study is to correlate T2 cutoff to the T1/T2 ratio and saturation using NMR data alone. Cores from sandstones and carbonates were used and NMR T2 and T1T2 measurements were performed at various water saturations for each core sample. The findings show average cutoff values of 119 ms for carbonates and 26 ms for sandstones. Correlations were established between T2 cutoff and water saturation, T2 cutoff and T1/T2 ratio, and T1/T2 ratio with water saturation. These correlations, based solely on NMR data, can be applied to logs when T2 cutoff data from cores is unavailable. The study demonstrates strong correlations between T2 cutoff, irreducible water saturations, and the T1/T2 log mean ratio, confirming the relevance and applicability of these correlations for downhole data.

1 Introduction

T2 cutoff is a critical parameter required in the processing of NMR data, especially for logs where it is near impossible to determine the proper saturation of the rock. However, determining the T2 cutoff is not straightforward and often requires experience with the specific reservoir. The standard method for obtaining a T2 cutoff is based on lab experiments, this process, however, is expensive and time-consuming, as it requires expensive coring and lab experimentation.

Figure 1 shows the data required to determine T2 cutoff. The top panel shows T2 distributions at fully water saturated (blue, P(T2) Sw1) conditions and irreducible water saturation (red P(T2) Swirr) after spinning the sample in air in a centrifuge. The bottom panel shows the same data in the cumulative domain. T2 cutoff is defined as the T2 value for which

$$sum(P(T_2 < T_2cutoff)_{Sw1}) = sum(P(T_2)_{Swirr}) \qquad (1)$$

This can be easily determined graphically by looking at the cumulative distributions (bottom panel). The T2 cutoff is defined as the intersection between the asymptote at long T2 to the cumulative distribution at Swirr (thin red line) and the cumulative distribution at Sw1 (blue).

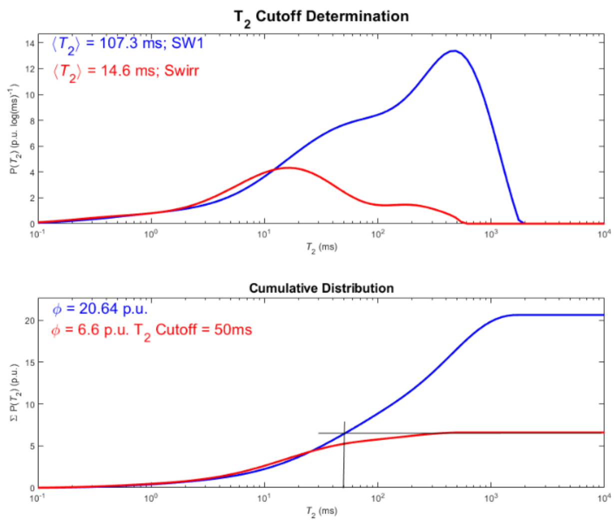

Figure 1: graphical determination of T2 cutoff

The advantages of having a downhole alternative to determine the T2 cutoff, rather than relying solely on laboratory methods, are obvious: availability right after logging (or even during), no coring required and no hectic lab work. Petrophysicists can develop workflows to estimate the value of T2 cutoff combining NMR with a priori information and other logging techniques. These techniques may rely on alternative saturation information (for example, dielectric measurements) or identify a

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section of the log (typically where the oil column is high enough) is at irreducible water saturation. In some cases, downhole testing measurements are also used in the workflows. There are two limitations to these workflows. First, they require measurements based on different physics which may not be readily available. Second, in most of the cases, these workflows might be location specific and, therefore might be limited to a reservoir or even a section of the well. It would be a great advantage to determine the aim of this study is to try to extract T2 cutoff from NMR data alone and correlate the T1/T2 ratio to the T2 cutoff for real-time applications.

1.1 Theory and Literature Review

The T2 cutoff is an indication of which part of the T2 spectra remains resistant to removal when the sample is de-saturated. This is therefore connected to the pore size, pore throat and wettability combined. NMR in principle is not sensitive to pore throat, but it is sensitive to pore size and wettability. The presence of a correlation between pore size and pore throat in most of the rocks enables determining permeability from NMR. The Timur-Coates equation (1969) describes a relationship between the free and bound fluid fractions (or equivalently T2 cutoff) and permeability [1]. This means that, to get permeability, you must know (or assume) T2 cutoff or free/bound fluid ratio a priori. As already mentioned, measuring T2 cutoff is a time-consuming process in the lab and knowing free/bound fluid from other logs requires same depth of investigation between NMR and other tools and (possibly strong) assumptions on free/bound fluids saturations.

$$\mathrm{K_{TIM}} = \mathrm{A_{TIM}} * 10^4 * \mathrm{Phi}^4 * [(\mathrm{Phi} - \mathrm{BFV})/\mathrm{BFV}]^2 \qquad (2)$$

The SDR equation takes a step further in simplifying the interpretation and puts into relationship the log mean value of T2 (T2lm) and porosity with permeability [2]. However, this interpretation implicitly includes the relationship between T2 and pore size, as well as the previously discussed connection between pore size and pore throat. The parameter controlling the pore size-T2 relationship is the relaxivity parameter ρ. This parameter is typically determined by comparing NMR measurements with other measurements determining pore size independently as microscopic images or mercury intrusion capillary pressure (MICP) which requires the usual assumption of pore body-pore throat relationship.

$$K_{SDR} = A_{SDR} * T2lm^2 * Phi^4 \qquad (3)$$

Recently, Cheng et al. (2017) suggested a new permeability prediction model based on the application of T1/T2 cutoff [3]. Singer et al. described techniques for partitioning the core- NMR T1-T2 data [4]. Kwak et al., presented methods of applying a generalized interpolation method, the RBF technique with a forward selection algorithm, to NMR T2 distribution data for predicting pore-throat-size distribution and permeability of a complex carbonate formation [5].

Simpson et al. (2018) [6] identified new NMR T2 cutoff parameters that give more accurate formation saturation analysis. They also outlined methods for correcting measurements for salinity, which need to be applied to NMR logs and core data to achieve more precise results. An alternative parameter known to provide information on surface interactions - and therefore on binding strength between fluid and rock - is the ratio between the two relaxation times, T1 and T2. When the other parameters are kept constant, the T1/T2 ratio parameter is expected to be in good relationship with wettability [7]. On water wet, water saturated cores, the wettability condition is well understood. Therefore, the T1/T2 ratio may indicate the strength of the water's binding to the surface.

Historically, the study of T1 for well logging applications experienced a period of reduced emphasis. The earliest downhole tools were designed to measure T1, since T1 is less sensitive to internal gradients and requires less demanding hardware. However, T1 measurement are typically time consuming, a significant disadvantage in downhole environment due to the high cost of rig time. As hardware capabilities improved and the understanding of basic physics advanced, T2 measurements, sometime combined with diffusion measurements, became more prominent. T1 information was still acquired but with few wait times and therefore not as accurate as the T2 measurements.

A demonstration of the general push towards study of T1 and T2 combined is the latest generation NMR logging technique able to measure both T1 and T2, simultaneously and both with much higher accuracy than before. The availability of this new hardware makes the application of T1-T2 based techniques in downhole environments much easier, thereby significantly increasing the business impact of studying the relationship between these two relaxation parameters.

2 Sample Selection and Workflow

The sample selection for this study included both carbonate and sandstone formations, providing a diverse range of geological characteristics for analysis. For all rock types, outcrop samples (Indiana, Berea, san saba, colton and carbon tan) were used. A total of 7 carbonate samples and 4 sandstone samples were selected for this study. The carbonate samples had a permeability range from 7 to 400 mD. The sandstones had a range from 0.4 to 200mD. Both the carbonate (NMR-ID: 1,2,3,4,8,10,71) and the sandstone (NMR-ID: 11,12,13,14) samples with their petrophysical properties are listed below in **Table 1**.

Table 1: Selected Carbonate and Sandstone samples

NMR ID	Sample ID	L (cm)	D (cm)	Bulk vol (cc)
1	B101-C-1	4.98	3.74	54.80
2	B101-C-2	4.98	3.74	54.76
3	B101-C-3	4.98	3.74	54.73
4	B101-C-4	4.95	3.74	54.42
11	SS1-2	4.90	3.81	55.94
12	BA1-1	4.85	3.81	55.37
8	B101-A-8	4.89	3.73	53.48
10	B101-A-10	4.88	3.73	53.48
14	CN1-1	4.87	3.81	55.55
71	B101-C-71	4.87	3.75	53.84
13	CT1-1	4.90	3.81	55.97

2.1 Workflow for carbonates and Sandstones

First, we performed the T1-T2 correlation experiment on core samples under fully water saturated condition (SW1), enabling us to extract information on the T1/T2 ratio. T1-T2 is a 2-D experiment where T1 and T2 relaxations are measured simultaneously. The core samples are then centrifuged with air at different speeds to attain lower water saturation i.e. Sw = Swirr,air. NMR measurements are performed at each water saturation state. Using these data, a correlation between the T1/T2 ratio of the remaining water fraction is examined, as a possible approach to separate the bound and free fluid fractions i.e. cutoff based on the T1/T2 ratio. To avoid the influence of wettability, cleaned, water-wet outcrops samples were used. The core samples were saturated with 57kppm equivalent NaCl brine. The workflow is graphically presented below (Figure 2).

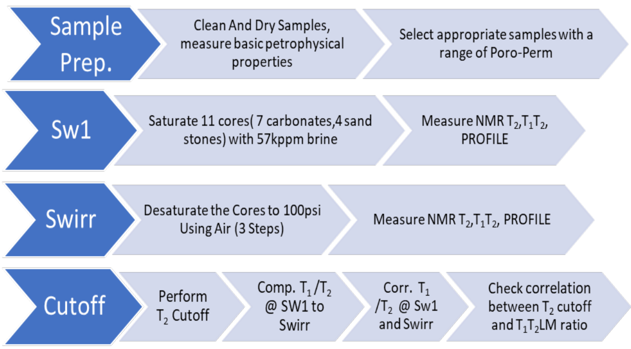

Figure 2: Workflow for Carbonates and Sand stones

3 Materials and Experimentation

3.1 Core Cleaning

As mentioned earlier, all the samples used in this study are outcrop samples which have not seen oil. However, there might be some contamination during the cutting process at quarry; hence, core cleaning was performed for all the samples included in this study to mitigate the risk of any oil contamination. The carbonates and the sandstones were cleaned in Soxhlet using toluene and methanol for 2 days each followed by drying in a vacuum oven following the API RP 40 procedures [8].

3.2 Porosity and Permeability

Porosity and permeability measurements were performed for all samples including shale samples. The porosity measurements were performed using the Helium Cup method (Boyle's Law) in a Temco HP-401 porosimeter for carbonates and sandstones. The permeability and the porosity at 500 psi of confining pressure were measured using the Coretest P-608 Automated permeameter for carbonates and sandstones. The Temco HP-401 measures the grain volume of the sample and the AP-608 permeameter works using the pressure decay method. The porosity and permeability data for carbonates and sandstones are listed in **Table 2**

Table 2 ; basic petrophysical properties of samples

NMR ID	Grain Vol (cc)	Pore Vol (cc)	He Porosity (%)	Satn. Porosity (%)	Perm (mD)
1	45.93	8.50	16.20	15.51	386.00
2	46.05	8.33	15.91	15.21	265.78
3	46.25	8.20	15.48	14.99	347.87
4	45.85	8.23	15.73	15.12	397.61
11	43.94	11.80	21.47	21.10	76.30
12	44.02	11.00	20.48	19.87	194.20
8	45.32	8.15	15.26	15.25	6.80
10	45.00	8.39	15.87	15.69	10.44
14	49.42	6.03	11.00	10.86	0.41
71	43.24	10.60	19.95	19.69	42.07
13	46.64	9.05	16.66	16.17	40.78

3.3 Core Saturation

All the core samples were saturated with 57kppm equivalent NaCl brine. The samples were initially vacuumed for 4-6 hours in case of carbonates and sand stones (C & SS, respectively). The brine was then introduced to the samples and the samples were pressurized overnight both for C & SS samples. Each sample was weighed before and after saturation. The dry and saturated weights were used to calculate the saturation porosity for all samples (**Table 2**). A plot of saturation porosity vs. helium porosity for all samples is shown in **Figure 3**.

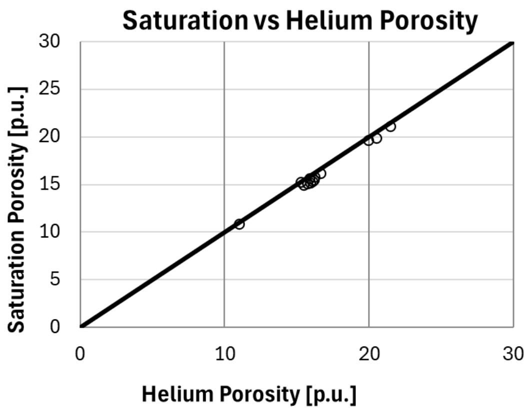

Figure 3: Saturation porosity vs Helium porosity

3.4 NMR Measurements

The NMR measurements in this study were performed using a 2 MHz NMR spectrometer from Oxford Instruments. For the scope of the study T2 and T1-T2 measurements were performed on all the samples at various water saturation states, i.e. fully water saturated (SW1) and partial water saturations (Swirr1, Swirr2, Swirr3). Swirr1 is the water saturation after spinning the sample at the lowest speed. The samples were then removed and weighed to determine the first partial saturation i.e. Swirr1. Similarly, the Swirr2 and Swirr3 are the partial saturations at 2nd and 3rd desaturation step.
The T2 relaxation time measurements were performed using the CPMG sequence with an inter-echo time of techo = 200 and 400 µs with a repetition delay (RD) of 13s and CPMG time of 10s. The T1-T2 measurements were performed using an inversion recovery sequence with 24 steps ranging from 200 µs up to 13 s, followed by a CPMG acquisition for T2 encoding. Each core sample required about 3.5 hours of experimentation time. The acquisition parameters for the carbonates and sandstones were the same. NMR data acquisition parameters are summarized in **Table 3**.

Table 3: NMR Parameters

NMR Parameter	Carbonate and Sandstone
t_{echo} (ms) for T_2	200
CPMG (s)	10
RD	13
t_{echo} (ms) for T_1T_2	200
Number of Scans T_2	16

3.5 Core Desaturation

An Ultra Rock Centrifuge (URC-628) was used to desaturate all the rock samples in this study from fully water saturated to lower water saturations in 3 steps. The samples were measured in sets of three, with each set chosen to include plugs of similar lengths and permeability whenever possible, to ensure consistent capillary pressure among the samples within the same set. The samples were spun for 16-24 hours for each desaturation step for both carbonates and sandstones. The centrifugation was performed at ambient conditions. The conversion between rotational speed and capillary pressure was calculated using the Hassler-Brunner equation:

$$Pc = 0.5 * \Delta\rho * \omega * (r_o^2 - r_i^2) \quad (4)$$

where Δρ is the density contrast of the fluids (in this case 57 kppm brine with a density of 1.035 g/cc and air with a density of 0.001 g/cm3), r_o is the arm length from the rotor to the outer face of the plug (9.126 cm), r_i is the arm length from the rotor to the inner face of the plug (dependent on sample length), and ω is the angular velocity.
The desaturation for the carbonate and the sandstone samples was performed at capillary pressures of about 2, 15 and 100 psi. As mentioned, the max capillary pressure applied was 100 psi to make sure that no grains are lost i.e. no physical damage is incurred on the core samples. Furthermore, it was intended to spin each sample to the same capillary pressure. The average saturation was calculated by the gravimetric method, using the difference in weight of core plugs before and after centrifugation divided by the Δρ, the difference in the density of brine and air (eqn. 2).

$$Sw_{avg} = (W_{before} - W_{after})/(\rho_w - \rho_{air}) \quad (5)$$

4 Results and Discussion

4.1 NMR Porosity @ SW1 (Carbonates & Sandstones)

NMR T2 measurements were carried out on carbonateand sandstone samples in a fully water-saturated state, and NMR porosity was measured for all samples. In **Figure 4** and **Figure 5** NMR porosity is plotted against both gas porosity and saturation porosity. We observe a very good match among the porosity values, with NMR porosity generally being slightly higher than both helium porosity and saturation porosity.

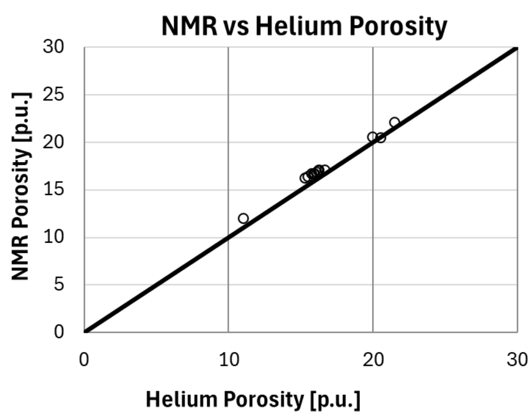

Figure 4: NMR vs Helium Porosity

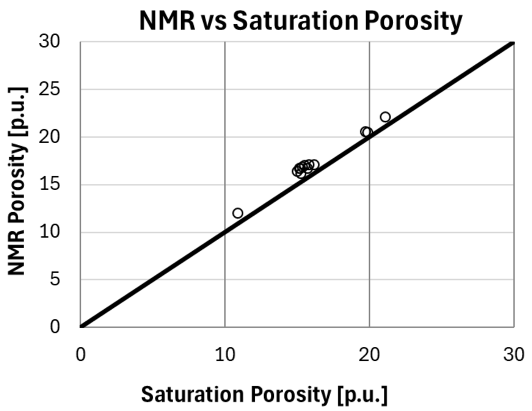

Figure 5: NMR vs Saturation Porosity

4.1.1 Carbonates

The carbonate samples were desaturated using 3 capillary pressure steps as mentioned earlier. The saturation steps are labelled as Swirr1, Swirr2 and Swirr3 for first, second and third desaturation steps. NMR T2 and T1T2 measurements were performed at each saturation step. The T2 distribution was used to calculate the T2 cutoff at each saturation step. The data collected from T1T2 measurements is the T1T2 maps and the T1/T2 log mean ratios. The saturations, T2 Cutoffs and T1T2 LM ratios are summarized in **Table 4** below.

Table 4: Sw, T1/T2 LM ratios and T2 Cutoffs for Carbonate samples

	B101-C-1	**B101-C-2**	**B101-C-3**	**B101-C-4**	**B101-C-71**	**B101-A-8**	**B101-A-10**
SW1	1	1	1	1	1	1	1
Swirr1	0.59	0.63	0.59	0.64	0.67	0.98	0.97
Swirr2	0.44	0.46	0.44	0.49	0.42	0.76	0.71
Swirr3	0.29	0.3	0.29	0.33	0.26	0.36	0.34
T_1/T_2 LM (SW1)	1.69	1.74	1.71	1.68	1.62	2.32	2
T_1/T_2 LM (Swirr1)	1.86	1.75	1.85	1.61	1.84	1.87	1.8
T_1/T_2 LM (Swirr2)	2.1	1.9	2.07	1.84	1.9	2.19	1.88
T_1/T_2 LM (Swirr3)	2.31	2.24	2.23	2.18	2.23	2.43	2.31
T_2_Cutoff 1 (ms)	546	546	546	614	343	1300	1300
T_2_Cutoff 2 (ms)	305	305	305	272	135	600	546
T_2_Cutoff 3 (ms)	135	135	135	121	53	135	121

The values of Swirr, T1/T2 log mean ratios and T2 Cutoffs were averaged for each respective desaturation step for all samples together. The averaged values are listed below in **Table 5**. The average T2 Cutoff value is 119 ms. It is important to note that generally a 100 or 200ms are used as the typical T2 Cutoff values for carbonates [9]. Sample B101-C-71 has a much lower T2 Cutoff of around 54 ms, this means that the sample has its high permeability since there is a lot more movable fluid compared to the other carbonate samples measured in this study. Furthermore, the log mean T2 is also much lower than the other carbonate samples measured which can explain the lower T2 Cutoff.

Table 5: Average values for Carbonate samples

Average Values	**Carbonates**
Satn. Porosity (%)	15.92
Perm (mD)	235.75
SW1	1.00
Swirr1	0.72
Swirr2	0.53
Swirr3	0.31
T_1/T_2LM (SW1)	1.82
T_1/T_2LM (Swirr1)	1.80
T_1/T_2LM (Swirr2)	1.98
T_1/T_2LM (Swirr3)	2.27
T_2_Cutoff 1 (ms)	742.09
T_2_Cutoff 2 (ms)	352.60
T_2_Cutoff 3 (ms)	119.27

The data analysis involved plotting different values on a crossplot and analysing if there is a correlation between the plotted values. The first plot is the T2 Cutoff vs the average water saturation in **Figure 6**. We observe a very stable and strong correlation between the two variables based on the linear regression.

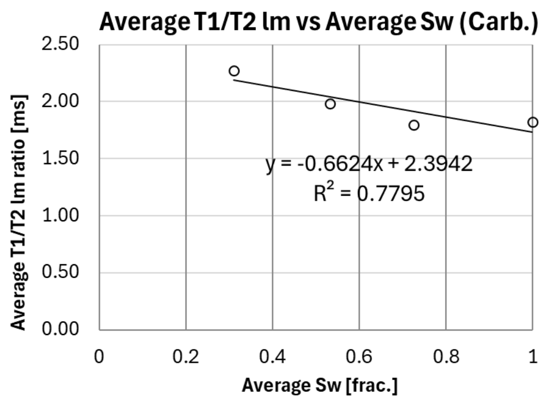

Figure 6: Average T2 Cutoff vs Water Saturation

The average T2 Cutoff was then plotted against the average T1/T2 LM ratio and is shown in the **Figure 7**. The T2 Cutoff is inversely proportional to the average T1/T2 LM ratio. Here also we observe a very strong correlation.

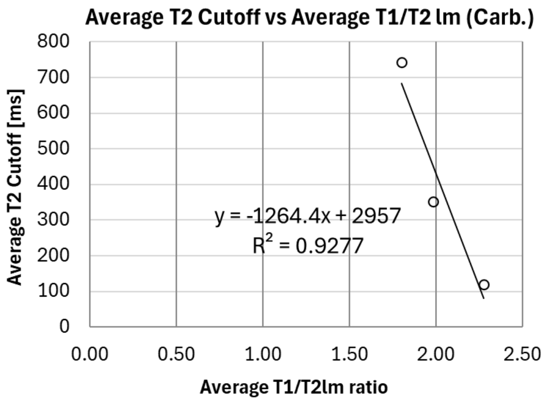

Figure 7: Average T2 Cutoff vs average T1/T2 LM ratio

The average T1/T2 LM ratio was also plotted against the average water saturation, Sw (**Figure 8**) and we also see a good negative correlation between the two i.e. the value of average T1/T2 LM ratio increases as the value of average Sw decreases.

2.3

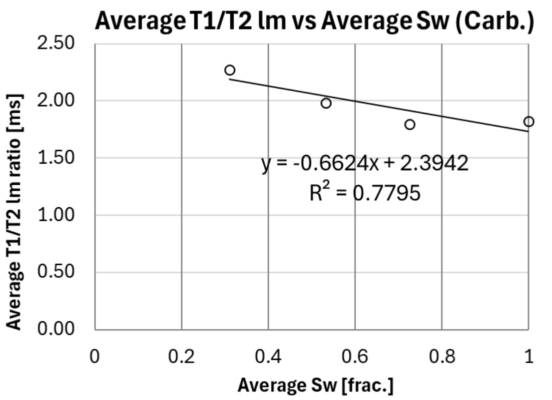

Figure 8: Average T1/T2 LM ratio vs Average water saturation

4.1.2 Sandstones

Similarly to the carbonate samples, the sandstone samples were also centrifuged in 3 steps (2, 12 and 100 psi). The samples had a porosity range from 10 to 21 % and a permeability range from 0.4 to roughly 200 mD. The samples were centrifuged in groups of similar permeability and length. The samples were centrifuged for 16 to 24 hours for each step. The results are summarized below in **Table 6**. The values for T2 cutoffs vary for sandstones as described in earlier studies [10,11]. We also see a slight variation in the T2 cutoff for sandstone samples.

Table 6: Sw, T1/T2 LM ratios and T2 Cutoffs for Sandstone samples

	SS1-2	BA1-1	CN1-1	CT1-1
SW1	1.00	1.00	1.00	1.00
Swirr1	0.98	0.98	0.98	0.98
Swirr2	0.50	0.38	0.97	0.54
Swirr3	0.24	0.17	0.76	0.33
T_1/T_2LM (SW1)	1.43	1.40	1.87	1.89
T_1/T_2LM (Swirr1)	1.38	1.42	1.91	1.91
T_1/T_2LM (Swirr2)	1.56	1.85	1.94	2.11
T_1/T_2LM (Swirr3)	1.81	2.44	1.88	2.51
T_2_Cutoff 1 (ms)	343	546	135	869
T_2_Cutoff 2 (ms)	50	120	121	107
T_2_Cutoff 3 (ms)	13	37	21	33

The values of Swirr, T1/T2 log mean ratios and T2 Cutoffs were averaged for each respective desaturation step for all samples together (**Table 7**). The T2 Cutoff values ranged from 13 to 38 ms for the samples analysed at about 100 psi capillary pressure. Sample 11 has the lowest T2 Cutoff of 13.22ms among the sandstone samples, this could be explained by the T2 distribution which has a T2 log mean of 2.4ms at Swirr3(~24%) exhibiting a huge decrease in T2 log mean of roughly 32ms. The average T2 Cutoff value is 26 ms. It is important to note that 33 ms is used as the typical T2 Cutoff value for sandstones.

Table 7: Average values for Sandstone samples

Average Values	Sand Stones
Satn. Porosity (%)	17.00
Perm (mD)	77.92
SW1	1.00
Swirr1	0.98
Swirr2	0.60
Swirr3	0.37
T1/T2LM (SW1)	1.65
T1/T2LM (Swirr1)	1.66
T1/T2LM (Swirr2)	1.86
T1/T2LM (Swirr3)	2.16
T2_Cutoff 1 (ms)	474
T2_Cutoff 2 (ms)	100
T2_Cutoff 3 (ms)	29

The first plot is the T2 Cutoff vs the average water saturation in **Figure *9*** for sand stones. We observe a very stable and strong correlation between the two variables based on the linear regression with an R2 value of 0.9547. **Figure 10** also exhibits a moderately strong correlation between T2 Cutoff and T1/T2 log mean ratio with an R2 value of nearly 0.8. Furthermore, there is also a strong correlation between T1/T2 log mean ratio and average saturation (**Figure 11**), with an R2 value of 0.9507.

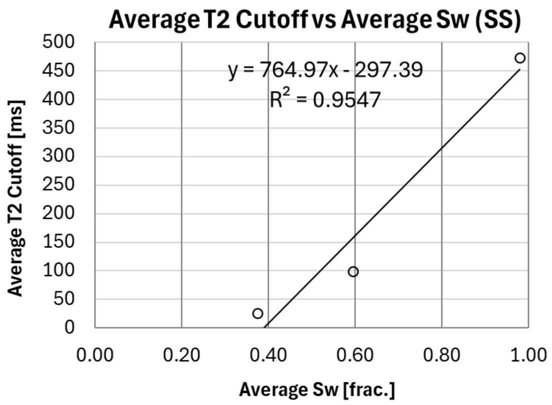

Figure 9: Average T2 Cutoff vs Water Saturation (SS)

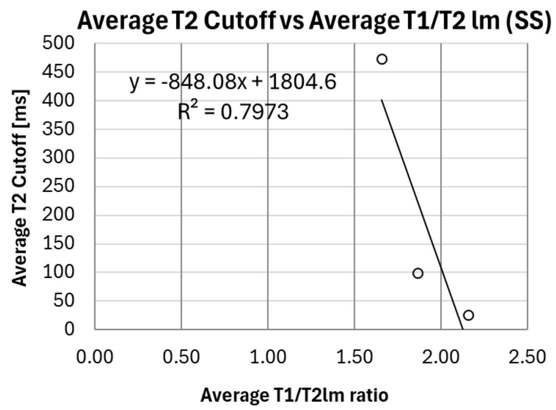

Figure 10: Average T2 Cutoff vs Average T1/T2lm (SS)

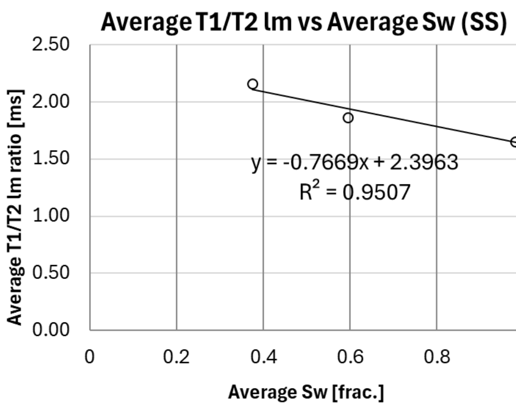

Figure 11: Average T1/T2lm vs Average Sw (SS)

4.2 Correlations Summarized

All the correlations developed in this study for carbonates (C) and sandstones (SS) are listed below in **Table 8** with the R2 representing the coefficient of determination for quality of fit. We observe a strong correlation among T2 cutoff, Saturation, and T1/T2 ratio, and in general for all. T2 cutoff vs Saturation have high R2 values for both rock types. These correlations provide ways to obtain any of the above-mentioned parameters with relative ease in the presence of NMR data alone.

Table 8: Correlations Summarized

	Correlation	**R^2**
	Carbonate	
T_2 Cutoff vs Sw	T_2 Cutoff = 1493*Sw-375.72	0.97
T_1/T_2lm vs Sw	T_1/T_2lm = -0.6624*Sw+2.3942	0.78
T_2 Cutoff vs T_1/T_2lm	T_2 Cutoff = -1264.4*T_1/T_2lm+2957	0.93
	Sandstone	
T_2 Cutoff vs Sw	T_2 Cutoff = 764.97*Sw-297.39	0.96
T_1/T_2lm vs Sw	T_1/T_2lm = -0.7669*Sw+2.3963	0.95
T_2 Cutoff vs T_1/T_2lm	T_2 Cutoff = -848.08*T_1/T_2lm+1804.6	0.8

5 Application of Correlation to the Logs

The correlations developed for different formation types have been applied to NMR wireline logging data recorded in various formations. The log responses and analyses support the evidence of strong correlations between T2 cutoff, irreducible water saturations, and the T1/T2 log mean ratio, supporting the applicability of the correlation factors derived in the laboratory. NMR logging technologies provide important information about rock properties, including porosity, movable fluid porosity, fluid ability to flow, rock permeability, and pore size distribution. The simultaneous acquisition of T2 relaxation times, T1 polarization times, and Diffusion components also enables the description of fluid types within the volume of investigation of the measurements. In T2-based recording mode, an inversion process converts the echo signal train into the distribution of relaxation times (T2 distribution). Three main relaxation (signal decay) mechanisms contribute to the shape of the T2 distribution: surface relaxation rate, intrinsic bulk relaxation rate, and diffusion relaxation rate. The T2 distribution at each depth level can be represented as a linear sum of volumetric contributions from fluid and pore size constituents in the logged formation. Once accurately recorded, the NMR T2 signal amplitude and characteristics can be used for pore structure evaluation, pore type characterization, capillary pressure reconstruction, calculation of porosity, and movable fluid saturation.

Common interpretation methods for NMR data involve dividing the signal into two components: a fast-relaxing part (bound fluid) and a slow-relaxing part (free fluid). The T2 cutoff serves as the key parameter that determines this division. Several studies and logs evaluations performed in different formations and downhole conditions indicate that the T2 cutoff is not a fixed parameter and can vary even across the same lithology. The T2 cutoff value for NMR downhole measurements is influenced by several factors, including lithology, pore types, wettability, temperature, pore structure, irreducible water saturation, formation pressure, cation exchange capacity, and magnetic susceptibility.

The correlations among T2 cutoff and other NMR properties developed in the lab can significantly enhance the interpretation of downhole NMR data and provide representative rock parameters from NMR distributions during operational times. This limits the need for lengthy and extensive core lab analysis or other petrophysical or reservoir logging measurements serving as in situ calibration points. When applying the novel lab correlations, it is important to consider that NMR T2 distributions recorded downhole contain information about both pore size and fluid properties. The presence of hydrocarbons may also affect the T2 distribution and T2 cutoff values. Often, the distribution of water and hydrocarbons overlap, making it difficult to separate the two fluids using T2 cutoffs.

In the presence of gas, the NMR signal amplitude is underestimated, and the T2 distribution is not representative of the pore volume unless corrected for the gas effect.

Past efforts to address the overlapping fluids problem relied on acquiring another T2 distribution by polarizing only the water phase with different wait times or by enhancing the hydrocarbon diffusion with different echo spacings [12, 13, 14]. Other authors (Freedman et al, 1998) used additional data, such as density, together with NMR in gas-bearing formations [15]. To overcome this complication, a fluid substitution methodology must be applied to the NMR data prior to running any evaluation, to correct the T2 distribution for any hydrocarbon or mud invading effect. Once this is done, the T2 distribution accurately represents the pore distribution, and the lab-defined correlations between NMR properties for precise T2 cutoff and signal analysis can be more easily applied. The fluid substitution technique involves replacing the hydrocarbon contribution in the T2 relaxation mechanism as if the pore system were fully water saturated. NMR measurements on water-saturated cores result in a distribution of T2 values that correspond to the distribution of pore sizes. A water-filled system allows the use of the T2 distribution for determining T2 cutoff, bound and free fluid, irreducible water volume and saturation, T1T2 log mean correlations, and more advanced applications such as rock typing and capillary pressure profiling.

To support the interpretation, the NMR Factor Analysis technique can be applied to extract the main components underlying the T2 distribution. Factor analysis is a statistical method where a T2 distribution can be expressed as a linear combination of the individual T2 distributions of various poro-fluid constituents. In a 100 percent water system, the factor analysis result is representative of the pore size constituents and can be used to determine the critical number of bins and their cutoffs, which in turn helps to determine the appropriate T2 cutoffs used in clastic and carbonate reservoirs. Fluid and pore size signatures derived using this method are used to invert for respective volumes.

Alongside T2 log, advanced multidimensional NMR logging tools can record a continuous log of the distribution of polarization times (T1 distribution) together with the T2 distribution. Recently, many authors used multi-dimensional NMR data to solve for water and hydrocarbons from T2, T1 and Diffusion maps. This enables further testing and evaluation of the correlation equations defined in the lab to better describe the NMR properties from the T1 and T2 combination. Similarly to the laboratory setting, the evaluation of unconventional reservoirs using NMR logging measurements requires dis-tinct acquisition schemes and interpretation approaches in downhole environments.

In conventional reservoirs, 2D-NMR fluid evaluation focuses on the free fluid portion of the total porosity, assuming that the bound fluid is irreducible water. Consequently, pulse sequences are tailored for long-relaxing fluids, with interpretations typically presuming free diffusion of hydrocarbon molecules in water-wet pores. However, this approach is unsuitable for unconventional reservoirs such as shale gas and shale oil, where the fast-relaxing fluids of interest are in the bound fluid region. The three causes of fast relaxation are small pore size, heavy oils, and wettability alteration. As a result, the definition of the T2 cutoff and other NMR properties is performed using a dedicated set of parameters and testing.

5.1 Field log example – Carbonates

The first field example describes the use of NMR log measurements to characterize the pores system and confirm the applicability of the correlations found in the lab to in situ NMR logging data for heterogeneous carbonate reservoirs. Multi-dimensional NMR logs are recorded with simultaneous acquisition of T2, T1, and Diffusion components, continuously on a depth log. To enable good polarization and signal quality, multiple echo spacings, number of echoes, and wait times are applied at slow logging speed. The NMR logs are combined with resistivity, neutron and density, and elemental spectroscopy logs for a comprehensive formation evaluation. The petrophysics logging run is followed by downhole testing for formation pressure and formation fluid sample collection.

The workflow adopted for applying the novel laboratory data to the logs' evaluation is as presented below in **Figure 12**.

1. Petrophysics log analysis
   - Lithology, porosity, rock and fluid volumes, saturations
   - Rock typing
2. NMR log processing
   - T1 and T2 distributions and NMR porosity
   - T1T2LM ratio computation and trend analysis
3. NMR-cores integration
   - T2cutoff by rock type using the lab-defined correlations
   - NMR calibrated log interpretation, permeability analysis

Figure 12: Workflow for Carbonates, application of lab data to logs.

A volumetric analysis of rock and fluids is performed using petrophysical logs, except for the NMR measurements, so to enable an independent assessment and comparison between NMR and the other petrophysics logs. The log interpretation outputs, including irreducible water volumes and saturations, are calibrated to cores data available from offset well. The subsequent formation testing program is optimized based on the petrophysical logs and NMR data.

As illustrated in the log plot in **Figure 13**, the NMR logs evaluation provides valuable information for improved understanding of rock quality and reservoir behavior.

The petrophysical properties related to the relative amount of intergranular and vuggy porosity correlate well with the long end of the NMR time distributions.

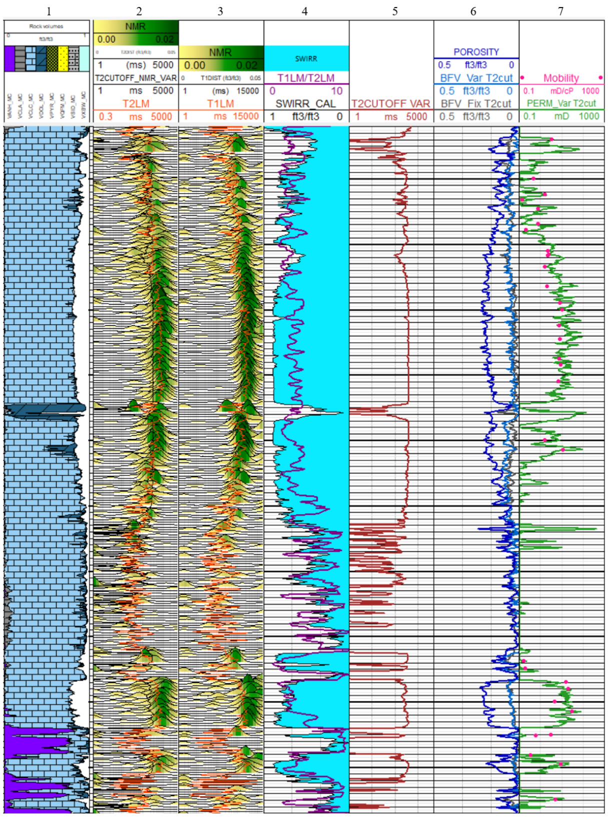

Figure 13: NMR log composite plot with T1 & T2 distribution information and variable T2 cutoff analysis. See large view at the end of the script **Figure 17**.

A continuous representation of rock mineralogy is presented in track 1. The T2 relaxation time and T1 polarization time continuous distributions are described in track 2 and 3 respectively; while in track 4 is the T1T2 log-mean ratio defined as the T1 log-mean (T1LM in track 3) divided to the T2 log-mean (T2 LM in track 2). The variations in T1T2 log-mean ratio with depth are consistent with the changes in the irreducible water saturation computed from the petrophysical analysis. This valuable information confirms that the ratio is a good indicator of changes in rock quality and pore distribution.

There is a clear correlation, as depicted in the lab study across the different core samples analyzed. The use of the average T2 cutoff value of 119ms as defined in the lab provides an average irreducible water saturation that aligns properly with the calibrated irreducible water saturation log from the other log interpretation across the main reservoirs. However, due to heterogeneity and textural variations, it is recommended to use a variable T2 cutoff that better accounts for changes in pore structure and fluid partitioning.

A representative average T2 cutoff (track 5) by rock type is obtained using the lab-based correlation between the average T1T2 log mean ratio and T2 cutoff variations defined during the study of the carbonate rock samples (Figure 7 in the previous section) as below:

$$AvgT2\ cutoff_{zone\,x} = -1264.4 * Avg\ T1T2\ LM\ ratio_{zone\,x} + 2957 \quad (6)$$

where the Avg T1/T2 LM ratio is the average ratio between the T1LM and then T2LM for each specific defined zone. The variable T2 cutoff is used for the computation of bound and free fluid. The comparison between the bound fluid from the variable T2 cutoff by rock type with the bound fluid from standard fixed T2 cutoff, indicates there is a significant impact on the rock quality assessment when adjusting the value, particularly in finer and more heterogeneous layers (track 6, **Figure 13**).

The bound fluid calculated using the variable cutoff was subsequently used for continuous permeability estimation which is validated against downhole testing data (track 7, **Figure 13**).

5.2 Field log example for Sandstones

The second field example demonstrates the applicability of the NMR correlations defined in the lab, along with T2 cutoff values and variations, across medium-low permeability reservoirs consisting of heterogeneous sand bodies with interbedded and dispersed clay and silt. The NMR logging tool was recorded using an expert pulse sequence consisting of 5000 spin echoes with an echo spacing of 200 microseconds and enhanced precision mode. The spin echo sequences are collected in pairs, called "phase-alternated pairs" (PAPS). The NMR logging tool is recorded in combination with standard triple combo petrophysics logs and elemental spectroscopy for in-situ rock parameter and reserves analysis.

The data processing and evaluation workflow applied (**Figure 14**) by applying the laboratory data to enhance the interpretation of the field log dataset comprises of three main steps as hereby indicated:

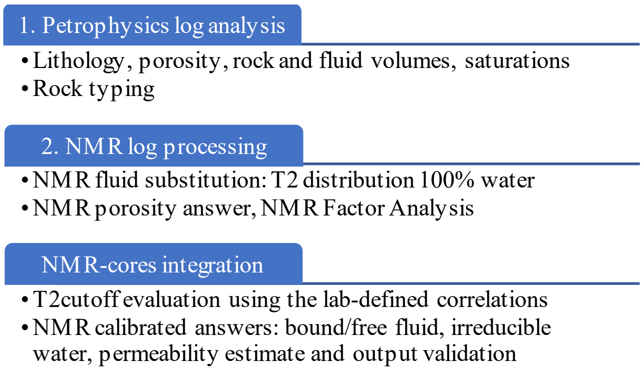

Figure 14: Workflow for Sandstones, application of lab data to logs.

The petrophysics logs are processed and interpreted to compute the main rock parameters, including the rock volumes, the porosity, and saturations. Alongside, the NMR logging data are quality controlled and processed to be ready for integration with the other logs measurements and assisting the evaluation of the pores' heterogeneity and distribution for rock quality and flow potential prediction. The main NMR log outputs and computations, assisted by the application of the NMR properties correlation defined in the lab, are described in the composite plot in **Figure 15**.

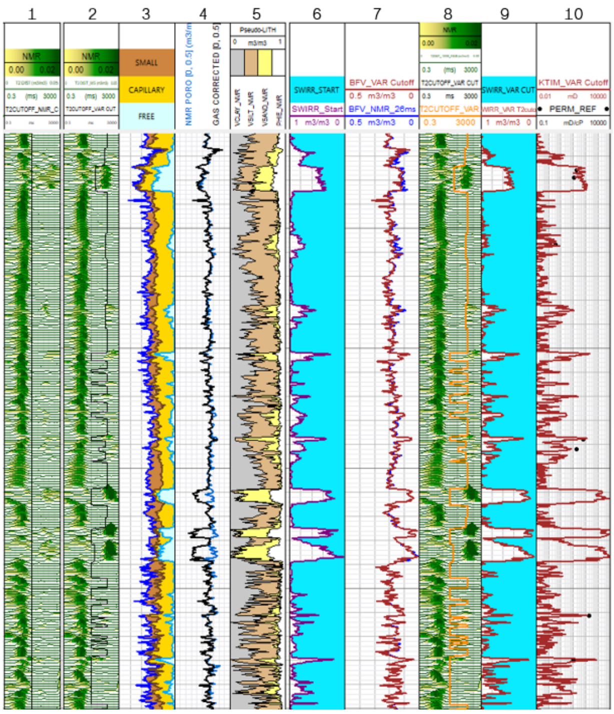

Figure 15: NMR log composite plot with main T2 distribution answer. See large view at the end of the script **Figure 18**.

Some of the reservoirs of interest are gas-bearing. To remove the gas effect from the NMR T2 data, the data are first processed using a fluid substitution technique to correct the NMR T2 amplitude and distribution for the lack of hydrogen index in presence of gas and for the OBM filtrate phase signal response. The fluid substituted T2 Distribution (100% water) is displayed in track 2 in **Figure 15** (T2_Dist_WS), versus the original T2 Distribution (still involving the combined contribution of pore distribution and fluids) in track 1. The fluid substituted T2 Distribution is then used to evaluate the rock quality and pore system for free fluid, continuous permeability, and rock classification. In absence of local calibration, the T2 cutoff of 26 ms (average value defined on the lab study) is considered as a starting point for NMR T2 logs interpretation. Alongside, the NMR Factor Analysis workflow is applied to the data for an independent quick assessment of the T2 cutoff between bound and free fluid, as well as the clay cutoff and other porosity partition. This workflow enables performing a statistical analysis of the T2 distribution to unlock the underlying pore-fluid constituents affecting NMR data over the entire interval. As illustrated in **Figure 16**, the T2 relaxation distribution is analytically decomposed into 9 main factors, highlighting the variable grain sorting and heterogeneous pores distribution of the formation. The main T2 cutoff picked based on the statistical analysis is 26 ms (cutoff between factors 4 and 5).

The value is consistent with the average T2 cutoff defined from the lab analysis of the sandstone core samples.

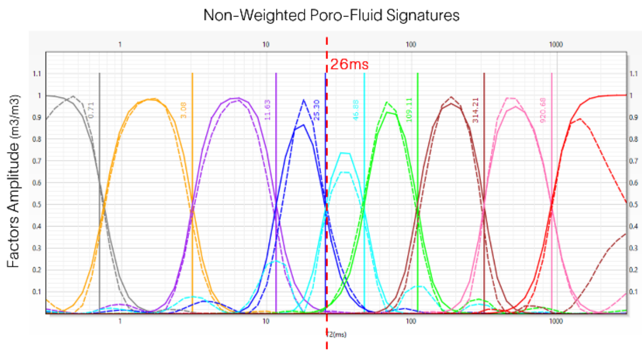

Figure 16: NMR non-weighted poro-fluid signatures from the NMR Factor Analysis applied to the completed logged interval data, covering the multiple stacked sandstone reservoirs.

The good comparison between the lab study and the results obtained from applying data analytics to downhole logging data enhances confidence in the applicability of the lab results to field data. This comparison supports further evaluation of the defined correlations when translated to the downhole environment. The average 26ms cutoff is used to calculate the NMR bound fluid volume from the fixed cutoff and define the starting NMR irreducible water saturation (track 6 in **Figure 15**) as

$$SWIRR_{Start} = BFV\_NMR\_26ms/Gas\ corr\_PORO \quad (7)$$

where BFV_NMR_26ms is the BFV computed using the 26 ms T2 cutoff and Gas corr_PORO is the NMR gas corrected porosity (track 4 in **Figure 15**).

The evaluation with fixed cutoff provides a valuable quick look assessment of the rock quality and rock parameters. However, to better capture variations in the rock pore system and facies, NMR logs are studied in more detail. This involves leveraging the NMR property correlations defined in the lab and validating their effectiveness when applied to logging measurements. To achieve this, the initial irreducible water saturation is analyzed on a reservoir-by-reservoir basis, zoning the intervals based on changes in rock quality, which are often apparent even within the same reservoir unit. For each zone, the average irreducible water saturation is calculated, so that a more specific average T2 cutoff by zone can be defined. This involves using the lab-defined correlation equation to establish a more specific average T2 cutoff for that zone using the correlation linking the average T2 cutoff to the average water saturation, for sandstone rock samples (**Figure 9** in the previous section) as below

$$Avg\ T2\ cutoff_{zone\ x} = 764.97\ Avg\ Swirr_{zone\ x} - 297.39 \quad (8)$$

This equation is applied to each defined zonation for a variable representative T2 cutoff estimation as shown in track 8 in **Figure 15**), along with the T2 distribution. The variable T2 cutoff is then used for refined calculations of bound and free fluid and irreducible water volume and saturation, as well as continuous permeability estimation. As shown in track 10, the NMR permeability computed with the variable T2 cutoff and gas-corrected NMR porosity compares well with the core permeability, providing direct evidence of the effectiveness of the lab-based approach and its applicability to evaluating logging measurements. Moreover, the NMR logs with variable cutoff are used to generate a clay, silt, sand model and solving for effective porosity from NMR data to assist the overall petrophysical evaluation of the clastic reservoirs. The lithology model, featured in track 5, aligns well with local knowledge and other well data.

6 Conclusion

In conclusion we successfully correlated the T1/T2 log mean (LM) ratio to the T2 cutoff and the water saturation for carbonates and sandstones. The average T2 cutoff values for carbonate and sandstone samples at the lowest water saturation achieved were 119 and 26 ms respectively. These cutoff values are different from the traditional values used. The correlations established through laboratory studies on core samples from various formation types have been applied to NMR logging data collected in different formations. The log responses and analyses demonstrate strong correlations between T2 cutoff, irreducible water saturations, and the T1/T2 log mean ratio, confirming the relevance of the correlation factors derived in the lab. The use of the lab-defined correlations is particularly useful in cases where NMR logs calibration is not possible, or refined outputs are requested to be obtained early in the process, during the operational time, without the need to wait for lengthy conventional core analysis results.

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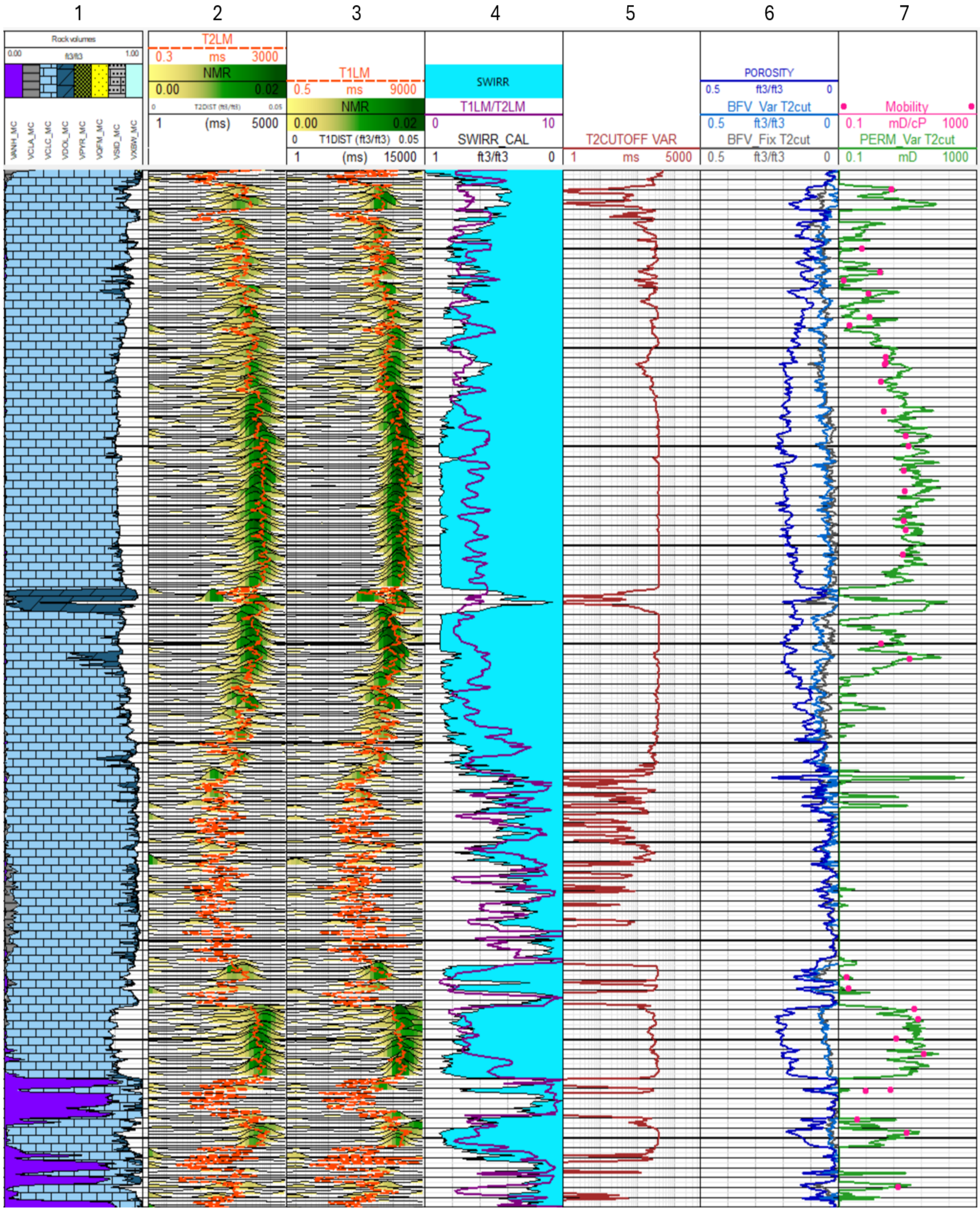

Figure 17: Enlarged View: NMR log composite plot with T1 & T2 distribution information and variable T2 cutoff analysis. Log plot scale 1:600MD.

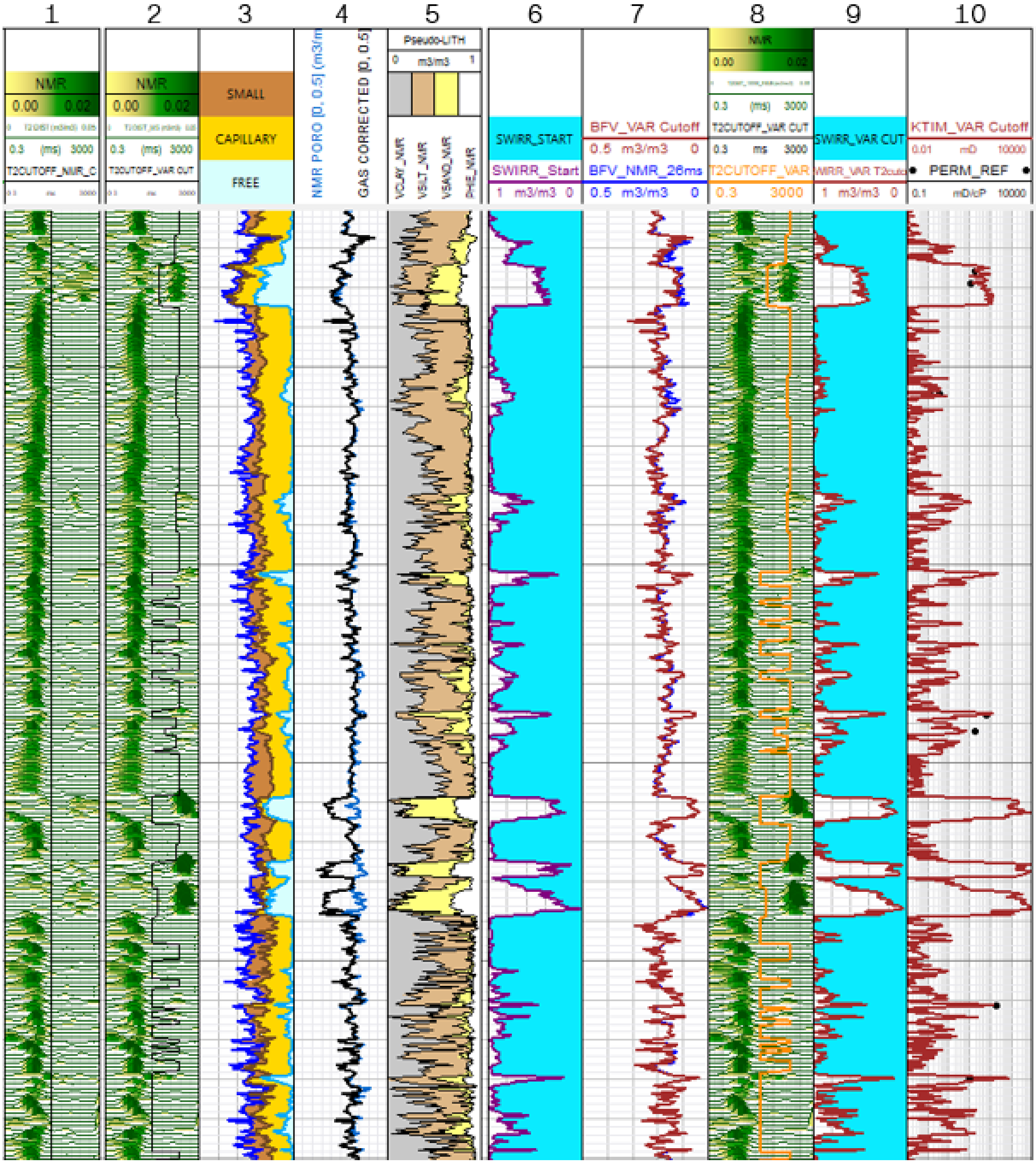

Figure 18: Enlarged View: NMR log composite plot with main T2 distribution answer (sandstone). Log plot scale 1:600MD.