



## Investigation of Transverse Relaxation Time (T2) Cut off of NMR log for better Electrofacies Modeling to understand production behavior of Heterogeneous Carbonate pay

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### Keywords

NMR, Formation Tester, T2 Cut off, Permeability, SOM, Electrofacies

### Summary

*Petrophysical evaluation of carbonate reservoir is always a challenging task. The degree of difficulty increases as the inherent heterogeneity increases in the reservoir pay due to its mineralogy and pore structure. This study investigates improvement of Electrofacies classification for carbonate reservoirs by proper modeling of permeability and free fluid volume (FFV). Due to the lack of core/lab data it is always a difficult task to calibrate the NMR permeability with the in-situ permeability, which plays an important role for the interpretation of flow ability of a pay zone. Porosity, FFV, Permeability and effective reservoir thickness ( $H_e$ ) are related to the reservoir quality in terms of its flow potential. The overestimation or underestimation of permeability, FFV and effective reservoir thickness affect the prediction of reservoir quality. The Formation Tester pretest mobility data can be used for re-computation of FFV and calibration of Permeability with proper cut off value. During the study it is seen that the Transverse Relaxation Time (T2) cut off can vary not only for the formation but with the reservoir/pay zone. Within this investigation, the Electrofacies modeling is also done with the statistical variation of wire line logging data sets such as Gamma Ray, Density, Neutron, Computed secondary porosity fraction, Calibrated Permeability and FFV over set intervals. The modified Electrofacies classification also supports the flow ability (Productivity Index) of the pay zones of the study area.*

### 1. Introduction

In the Western Offshore basin Mumbai, the Ratnagiri Formation is known to be highly heterogeneous and extremely challenging to characterize with the most prolific platform carbonates such as the lower Miocene L-III limestone. Other significant reservoirs are the L-II and L-IV limestone. L-II consists of

Limestone with thin shale at top and thick shale and Claystone at bottom. Limestone with thin shale streaks are present in L-III followed by alternating layers of Limestone and shale of L-IV. We have done our study with the wells of X, Y and Z areas. These are the most emerging and promising areas from the hydrocarbon point of view in Western Offshore.

Porosity, FFV, Permeability and effective reservoir thickness ( $H_e$ ) are related to the flow potential of a reservoir. For the prediction of reservoir quality, the overestimation/ underestimation of permeability, FFV and  $H_e$  can affect. Proper T2 cut off can be used to compute free fluid volumes, effective reservoir thickness ( $H_e$ ) and Permeability in L-III layer in Ratnagiri formation. This recomputed properties can be correctable with the production testing results as Productivity Index is a function of  $H_e$  and Permeability (Alarifi, 2015).

### 2. Challenges

Petrophysical evaluation of carbonate reservoir is a challenging task. The inherent heterogeneity increases in the reservoir pay due to its mineralogical heterogeneity, pore size, pore shape, pore structure distribution and connectedness etc. These are the main reasons behind the increase in degree of difficulty. It is also observed that the testing results are not supporting the interpretation drawn from log responses.

### 3. Geology of the Study area

The area under our study is located in the southwestern part of Mumbai High- Dominance of clastic sediments tectonic. Deep Continental Shelf (DCS) is noticed towards further north of Diu fault whereas a carbonate platform is seen to its south. Prominent structural high trends/spurs radiating from Bombay High are seen in the study area, which

## Remodeling of NMR T2 Cut off and Modified Electrofacies Classification

include the X, Y and Z areas. Wells, drilled on these structures are commercially hydrocarbon bearing from multiple stratigraphic levels dominantly carbonates of Early Miocene, Oligocene and Late to Middle Eocene age (Ratnagiri, Panvel, Heera, Mukta and Bassein) and to a lesser extent, in Eocene-Paleocene sands (Panna). The major hydrocarbon source rocks in the area west and NW of Bombay High are the Panna shales though some of the Oligocene shales also possess moderate to good source potential. Present study focuses on the accurate petrophysical evaluation of L-III in Ratnagiri formation (Figure 1).

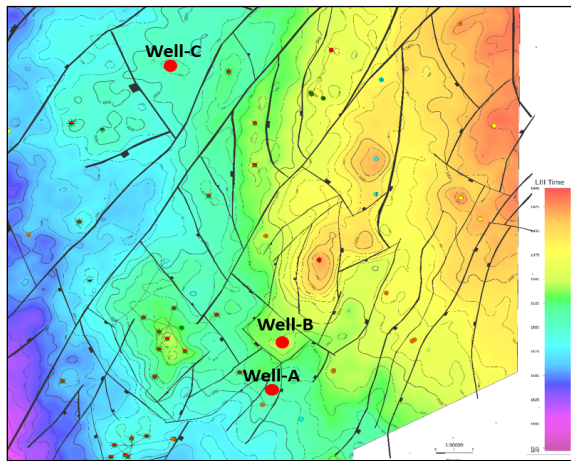


Figure 1: Time Map of LIII of Study area

### 4. Methodology

NMR tool is a reliable tool for interpretation as its response is lithology independent. To segregate bound fluid volume (BFV) & free fluid volume (FFV) standard 100ms T2 cut off value is used for carbonate reservoir. Although due to heterogeneity of, mineralogy, pore size, pore shape, pore structure distribution and connectedness, this can vary in different formation/Pay due to relaxivity mechanism of stratification. It is also observed that the production testing results are not supporting the preliminary interpretation, which has been drawn, after interpreting the NMR logs. Even sometimes the Petrophysical Elemental Analysis inversion volumes are not supportive to the NMR response sets. Which basically indicates that the free fluid volume (FFV) is

either underestimated or overestimated. In the general practice we take 100ms T2 cut off in NMR processing for carbonate reservoir. The modification or any change in the cut off value needs to be validated with the laboratory results. But as in every case it is difficult to get the laboratory data as quick decisions are to be made for testing. In such cases there is an option of calibration and validation of Permeability data of NMR logs with the help of Formation Tester data sets (Haldia, 2013) to get an idea of T2 cutoff value. Basically the mobility data from the Formation Tester is also a reliable source of in-situ permeability information which can be used to calibrate the permeability with the permeability derived from NMR.

Robust mathematical methods are used for the reduction of uncertainties and create more reliable the results to minimize exploration risks in terms of time and costs. Artificial Neural Networks (ANN) (Haykin, 1999) is the most used artificial intelligence technologies in geosciences. Self Organizing Maps (SOM), which is basically an ANN is used for the classification and modeling of electrofacies (Kushwaha, 2018). In our study using the SOM we have modified electrofacies classification, which is also supporting the flow ability (testing results) of the wells in the study area.

#### 4.1. Calibration of NMR Permeability with Formation Tester derived Permeability:

Although NMR is having very shallow depth of investigation around borehole (George, 1999) it's a very important tool in formation evaluation. The near borehole magnetic resonance signals are received and Nonlinear Inversion is performed to T2 echo signal, T2 distribution is modeled. Analyzing the T2 distribution, we can determine the formation total porosity pore size, pore shape, pore structure distribution and their connectedness. The free fluid volume and formation permeability can be computed depending upon the T2 cut off value during processing (Figure 4), which is 100ms (standard practice). During the pretest of the Formation Tester logging it gives the mobility information with the corresponding down hole temperature. After applying the temperature & pressure correction it is quite reliable to calibrate the permeability with the KTIM (Timur-Coates) permeability that is derived from

## Remodeling of NMR T2 Cut off and Modified Electrofacies Classification

NMR log. Hence we get the calibrated value of T2 cut off in reservoir level and that may differs from our standard 100ms cut off.

### 4.2. Self Organizing Maps (SOM) Data Analysis:

In the late 70s, Kohonen developed Self Organizing Maps (SOM), which is basically an ANN for unsupervised samples. It maps the input dataset into high dimensional group of pattern and searches for similarity in a multidimensional space created through any key well dataset by unsupervised learning. The algorithm is based on A competitive learning process is involved in this algorithm, where one computed output is called BMU (Best Matching Unit). In SOM module the input log responses/parameters are clustered in m nodes arranged in matrix.

Each well sample is a line-vector in the input layer, in in terms of data matrix (one dimensional variable) represented by the vector:

$$x = [x_1, x_2, \dots, x_n]$$

Each unit  $i$  is associated weight:

$$w_i = [w_{i1}, w_{i2}, \dots, w_{in}]^T$$

Learning Sequence of SOM:

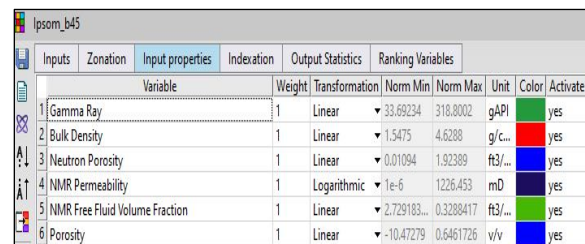
- The module starts by initializing of weight to random value  $0 < w_i < 1$ .
- Randomly a vector is chosen at from the set of input signal and presented to the matrix.
- Examination of every node for calculating which ones weight is most likely with input vector. The node is termed as BMU.
- The neighborhood of BMU is computed and hence the no of neighbor is decreased each time.
- For every iteration the weight, which is most likely to the input vector, is awarded as best fit and the neighbor is more like the sample vector
- Repeat step-b for upcoming iterations.

The Euclidean distance (the activation function) used to determine the likelihood of the weight with the current input vector:

$$d_i = \sum_{i=0}^n (x_i - w_i)^2$$

Where  $x_i$  is current input vector and  $w_i$  is weight of BMU for that iteration. After determining BMU by the minimum distance from the sample vector point, the distances between the unit and its neighbors are updated. This way they move closer to input vector in the output space.

In our study we have taken 6 inputs (Figure 2) with convention logs such as Gamma Ray, Bulk Density, Neutron Porosity, Secondary porosity fraction, Calibrated NMR Permeability and FFV over set intervals for better Electrofacies modeling. Six electrofacies are created using logs which are classified in terms of reservoir type. The classification is given in Figure 3.



Inputs	Zonation	Input properties	Indexation	Output Statistics	Ranking Variables				
		Variable	Weight	Transformation	Norm Min	Norm Max	Unit	Color	Activate
1		Gamma Ray	1	Linear	33.69234	318.0002	gAPI	Green	yes
2		Bulk Density	1	Linear	1.5475	4.6288	g/c...	Red	yes
3		Neutron Porosity	1	Linear	0.01094	1.92389	ft3/...	Blue	yes
4		NMR Permeability	1	Logarithmic	1e-6	1226.453	mD	Dark Blue	yes
5		NMR Free Fluid Volume Fraction	1	Linear	2.729183...	0.3288417	ft3/...	Light Green	yes
6		Porosity	1	Linear	-10.47279	0.6461726	v/v	Dark Blue	yes

Figure 2: SOM regression input vector

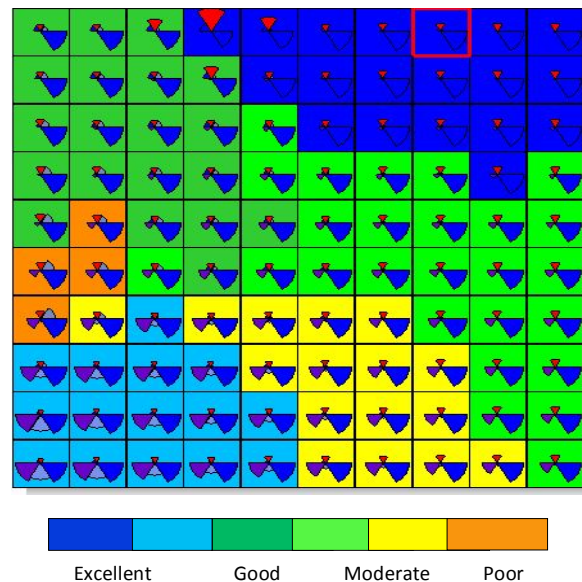


Figure 3: SOM Classification input Indexing

## Remodeling of NMR T2 Cut off and Modified Electrofacies Classification

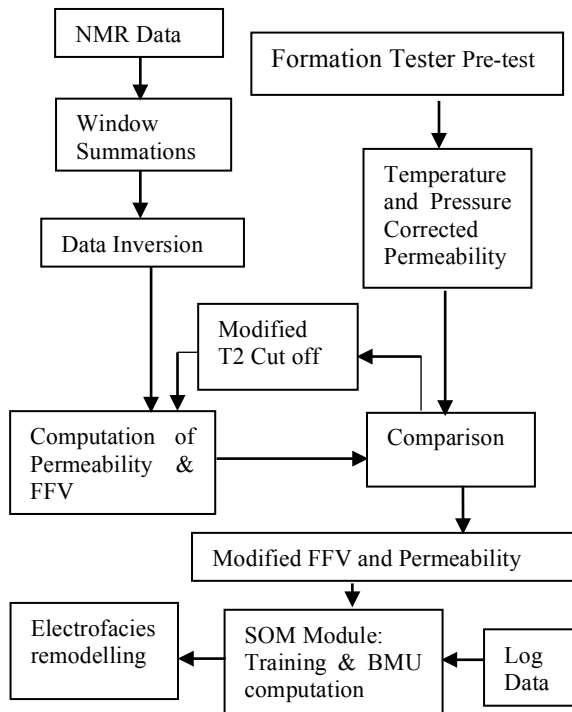


Figure 4: Workflow of modification of NMR Cut off and Electrofacies Modeling.

### 5. Results

In Petrophysical non-linear 1D inversion output, the significant hydrocarbon saturation is computed in the zone of interest. But in NMR log responses, it shows more bound fluid and underestimates the Free Fluid Volume (FFV). The computed permeability with the standard cut off of 100ms is also less. But the Formation Tester mobility and its Temperature-Pressure corrected Permeability is quite promising in those intervals.

After performing initial processing of Nonlinear Inversion with echo signals of one station or two substation readings, we have computed the NMR permeability of 5 wells at different cut off values ranging from 50-120ms. The NMR permeability and Formation Tester derived permeability holds very good correlation at the cut off value around 60ms in L-III (Figure 5).

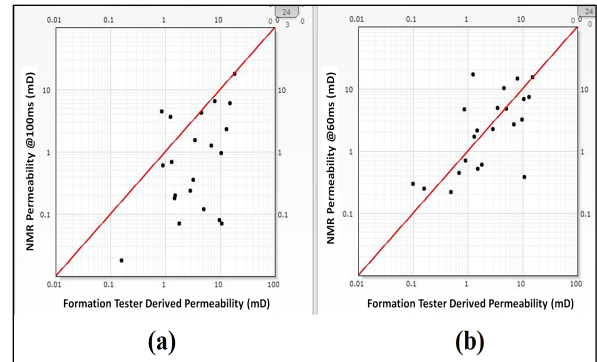


Figure 5: Correlation of Formation Tester derived permeability and T2 cut off modified NMR Permeability (KTIM) of 5 wells, (a) for 100ms, (b) for 60ms

The computed FFV at 60ms T2 cut off is enhanced by 3-5%. After the re-computation of FFV and NMR Permeability, the inputs are given to our SOM Electrofacies module. In all well it is seen that the Electrofacies classification made with the recomputed parameters are showing increment in effective thickness of reservoir ( $H_e$ ) which supports the production testing result.

In Well-A, ELAN volume is created which shows the interval X637.0m to X645.0m is having effective porosity in the range of 15-22% which is hydrocarbon bearing with  $Sw$ : 60-70% (Figure 6). In NMR log responses the interval is showing insignificant amount of free fluid and less permeability in major portion. But on testing the zone produced Oil (Qoil: 659 bpd) through  $\frac{1}{2}$ " choke @ FTHP: 230 psi.

Hence this clear contradiction between the flow ability of a zone and its interpretation from NMR log responses. Electrofacies is generated with the parameters calculated from 100ms & 60ms T2 cut off values, which are Facies-A1 and Facies-A2 respectively with 6 classes (Figure 7). From the SOM classification of Facies-A1, it is clear that the perforated zone is showing combination of good and moderate facies and the effective reservoir thickness is around 4.5 m only. Electrofacies correspond to 60ms cut off, i.e. Facies-A2, shows that the FFV is increased by 3-4% followed by the increase in permeability and  $H_e$  around 6.5 m. Hence the Productivity is well explained from the NMR log

### Remodeling of NMR T2 Cut off and Modified Electrofacies Classification

response.

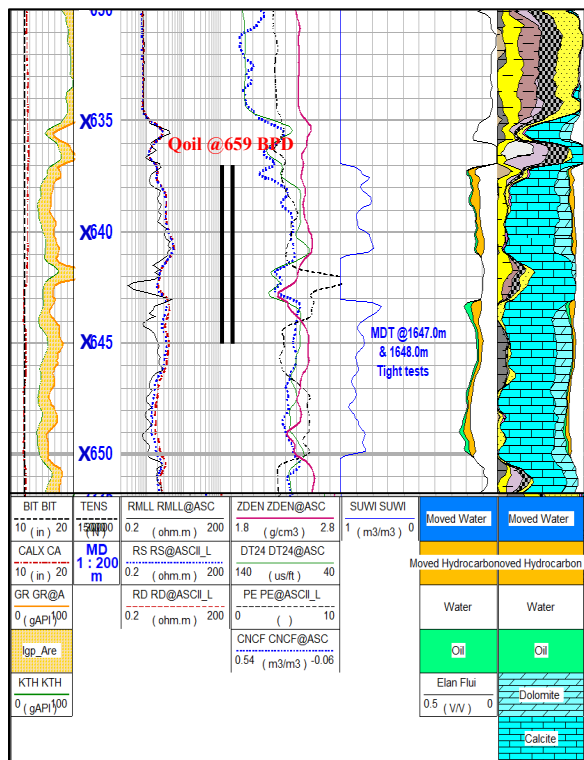


Figure 6: Petrophysical inversion output of Well-A

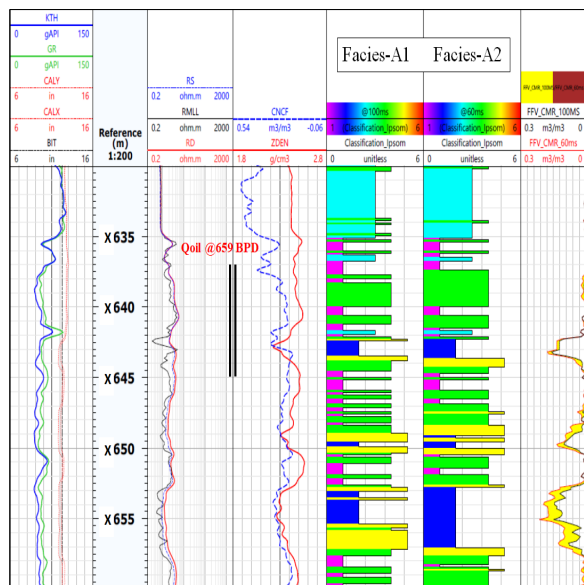


Figure 7: SOM Classified Electrofacies for Well: A

Well-B, another well of our study area, is also taken for the validation of our Classification group (Based on Well-A), which is created in SOM module. We have propagated the facies classification to Well-B, taking input parameters generated by 100ms and 60ms T2 cut off, i.e. Facies-B1 and Facies-B2 respectively (Figure 8).

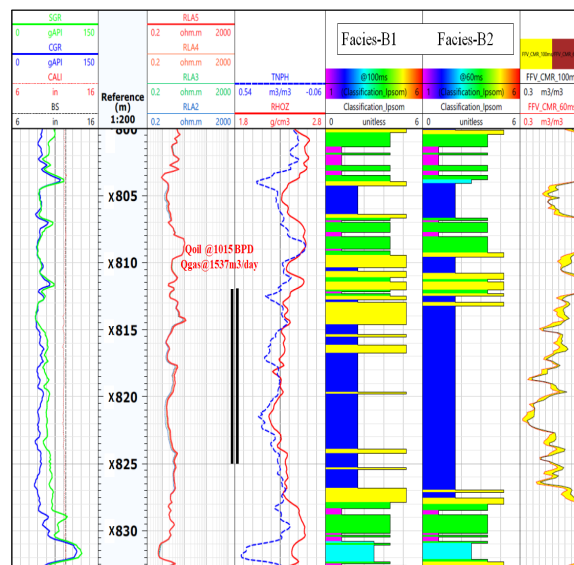


Figure 8: Propagation of Electrofacies for Well: B

From Facies-B1, it is clear that the perforated zone is showing combination of good and moderate to poor facies and the calculated effective reservoir thickness ( $H_e$ ) is around 9 m. But On testing, it produced Oil (Qoil: 1015 bpd) and Gas (Qgas: 1537 m<sup>3</sup>/day) through ½” choke @ FTHP: 230 psi.

Electrofacies correspond to 60ms cut off, i.e. Facies-B2, shows  $H_e$  around 13.0 m followed by the increase in FFV and permeability and. Hence the production testing results are relatable to the interpretation of the NMR log response.

In well-C we have propagated the facies classification to Well-A, taking input parameters generated by 100ms and 60ms T2 cut off, i.e. Facies-C1 and Facies-C2 respectively (Figure 9). In result Facies-C1 is showing the effective reservoir thickness of a perforated interval is ( $H_e$ ) around only 1.5m with

## Remodeling of NMR T2 Cut off and Modified Electrofacies Classification

the combination of good facies and dominantly moderate to poor facies. But on testing, it produced Oil (Qoil: 689 bpd) and Gas (Qgas: 6,197 m<sup>3</sup>/day) through ½” choke @ FTHP: 126 psi.

Electrofacies correspond to 60ms cut off, i.e. Facies-C2, shows H<sub>e</sub> around 5.0 m followed by the increase in FFV and permeability and. Again the Productivity is explainable from the enhanced H<sub>e</sub>, FFV and Permeability.

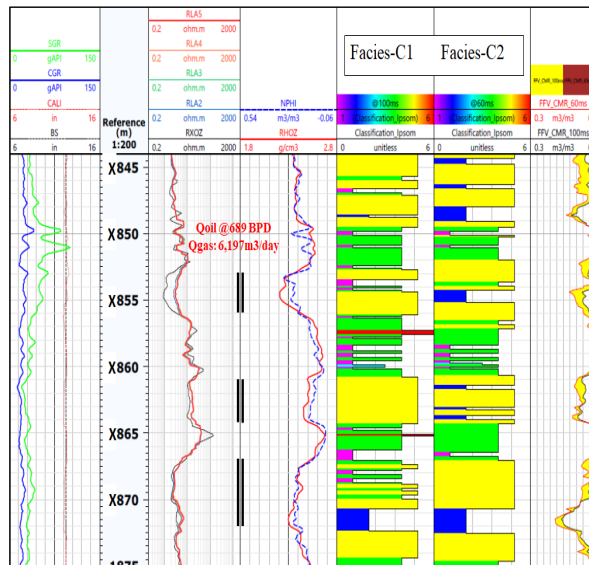


Figure 9: Propagation of Electrofacies for Well: C

## 6. Discussion and Conclusion

From the study it is seen that application of Standard T2 cut off (100ms) for L-III limestone in Ratnagiri Formation is not proper for the computation of free fluid (FFV) & bound fluid volume (BFV) from NMR log responses. Integrated study of Formation Tester Data and NMR data can be used for the remodeling of FFV and Permeability with modified T2 cut off. After the nonlinear inversion of NMR data, the modification of T2 cut off and the corresponding modified properties can be used as input in SOM. From the Electrofacies output the increased effective thickness supports the production testing results (i.e., defined as productivity index). Presence of fine grain minerals (e.g. Micrites) are reported in L-III in Core Report of other Wells in this study area. This may

cause heterogeneity and may be one of the factors responsible for reduction in T2 cut off value. In the composite logs and in petrophysical inversion volumes, it is also seen that there are presence of shale in the interval of our interest.

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