

IMPROVED POROSITY ESTIMATION IN TIGHT GAS RESERVOIRS FROM NMR AND DENSITY LOGS

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ABSTRACT

Nuclear magnetic resonance (NMR) logs differ from conventional neutron, density, sonic and resistivity logs because the NMR measurements provide information only on formation fluids and are generally insensitive to matrix properties. The main task of formation evaluation is to calculate accurate formation porosities, permeabilities and identify properly the nature and amount of saturating fluids (water, oil, gas). The focus of this paper is to present an empirical method in which density and NMR porosities are combined and calibrated to core. The new porosity is termed DMR (density-magnetic resonance) porosity.

Historically, neutron/density measurements have been used to derive formation porosity. While this yields acceptable results in clean liquid-filled lithologies (sands), the effects of lithology, hydrocarbon fill (gas), and formation heterogeneity in shaly sands increases the uncertainty in computed porosities. The technique of using combined NMR relaxation times and bulk density data described in this paper significantly reduces uncertainty in derived logging parameters through elimination of the neutron log. This removes the need to characterize, and correct for flushed zone fluid densities.

This paper describes the application of DMR technique in cored wells in the Obaiyed field; Western Desert, Egypt and it discuss the results obtained, limitations and benefits, along with the data acquisition requirements. Field examples demonstrate the importance of the (DMR) technique in place of the use of NMR or conventional logs separately in determining formation porosity and gas saturation in tight gas sand reservoirs.

INTRODUCTION

The field of interest, Obaiyed is located in the western desert of Egypt. It is Gas-Condensate field producing from the Mesozoic Lower Safa reservoir. The reservoir is classified as a tight gas reservoir due to compaction (4000m depth), very fine sand size and the presence of clay minerals (Kaolinite & Illite) which affect permeability to be in the range from 0.01 to 100 md micaceous sandstone deposited in a strongly tidally influenced estuary with 5-12% porosity and high lateral and vertical heterogeneity. Siderite locally found replacing mudstones and siltstones.

Due to the high heterogeneity of the reservoir; many cores were acquired in different wells covering different reservoir units to create the proper models for porosity and permeability for the different facies. As the first three facies units are one sand body of high Net/Gross value and it is difficult to differentiate between them. (2)

It was difficult to use one log alone to define the corrected porosity, as a result, Neutron-Density cross plots were used as a trial to calculate corrected gas porosity, but the neutron log response was not reliable in this case because of iron rich clay minerals and the absorbers of thermal neutrons like Cl (chlorite), Siderite and Glauconite. (5)

Nuclear Magnetic Resonance (NMR) log is better suited to be used in combination with density log in this case rather than neutron logs because NMR tools are sensitive only to hydrogen and fluid protons and no borehole correction is needed whenever the radius of investigation is beyond caliper measurements specially incase of MRIL tool (our case), except in case of very high saline mud, which will affect NMR measurements. (1), (3), (4) The NMR data shown below has been acquired via Halliburton Service Co. (MRIL tool) several wells in Obaiyed field; some of these wells are cored within the same interval. In the following chapter we will show the derivation of Density-Magnetic Resonance Porosity (DMRP) formula, calibrate this formula with the stress corrected core porosity. We will then apply the DMRP formula in our reservoir of interest and discuss the results and conclusions.

DENSITY-MAGNETIC RESONANCE POROSITY (DMRP).

The gas corrected porosity (ϕ) can be obtained by the combination of NMR and density log data. It is assumed that the invasion profile at the radius of investigation is the same for both the MRIL tool and Density tool. In low porosity reservoir (tight gas sands); the invasion profile does not change significantly with the depth of investigation. The NMR porosity response and density tool response equations will be combined and solved for gas corrected porosity as follows;

• **NMR Porosity Response**

$$\phi_{NMR} = \phi S_{gxo} HI_g P_g + \phi HI_L (1 - S_{gxo}) \quad Ref. (1)$$

Assume hydrogen index for liquid (HI_L)=1

$$\phi_{NMR} = \phi * [1 - S_{gxo} (1 - HI_g P_g)]$$

$$\frac{\phi_{NMR}}{\phi} = 1 - S_{gxo} (1 - HI_g P_g) \quad \dots\dots\dots (1)$$

Where;

- ϕ_{NMR} : Porosity of NMR tool
- HI_g: gas hydrogen index
- S_{gxo}: gas saturation in the flushed zone
- W: wait time
- ϕ : Gas corrected porosity
- HI_L: fluid hydrogen index (water + mud filtrate)
- $P_g = 1 - \exp(-W/T_{1,g})$: gas polarization factor
- T_{1,g}: gas longitudinal relaxation time.

• **Apparent Porosity From Density Equation**

$$\rho_b = \rho_m (1 - \phi) + \rho_L \phi (1 - S_{gxo}) + \rho_g \phi S_{gxo}$$

$$\phi_D = \frac{\rho_m - \rho_b}{\rho_m - \rho_L} = \frac{\rho_m - [\rho_m (1 - \phi) + \rho_L \phi (1 - S_{gxo}) + \rho_g \phi S_{gxo}]}{\rho_m - \rho_L}$$

$$\phi_D = \phi [1 + S_{gxo} (\frac{\rho_L - \rho_g}{\rho_m - \rho_L})]$$

$$\frac{\phi_D}{\phi} = 1 + S_{gxo} (\frac{\rho_L - \rho_g}{\rho_m - \rho_L}) \quad \dots\dots\dots (2)$$

Where;

- ρ_b : Bulk Density
- ϕ_D : Apparent porosity from density
- ρ_L : liquid Density (water + filtrate)
- ρ_g : Gas Density

• **Solution For Gas Corrected Porosity ϕ**

Assume constants β, α where, $\beta = \frac{\rho_L - \rho_g}{\rho_m - \rho_L}$ and $\alpha = (1 - HI_g P_g)$

Substitute in Eq. (1) & (2)

$$\frac{\phi_{NMR}}{\phi} = 1 - \alpha S_{gxo} \dots\dots\dots (3)$$

$$\frac{\phi_D}{\phi} = 1 + \beta S_{gxo} \dots\dots\dots (4)$$

Solution of equations 3&4 for True formation porosity (Φ)

$$\phi = \left(\frac{\alpha}{\beta + \alpha} * \phi_D + \frac{\beta}{\beta + \alpha} * \phi_{NMR} \right)$$

$$\phi = A * \phi_D + B * \phi_{NMR}$$

$$DMRP = \phi = A * \phi_D + B * \phi_{NMR} \dots\dots\dots (5)$$

A & B are constant where $A + B = \frac{\alpha}{\beta + \alpha} + \frac{\beta}{\beta + \alpha} = \frac{\beta + \alpha}{\beta + \alpha} = 1$

Calibration for DMR Porosity

A curve fitting method has been used to calibrate the A&B constants values which are applied to the reservoir of interest. In our case we have selected well (D7) of facies I (fine to moderate grain size and clay mineral content) where both core and NMR data were available over the same reservoir interval. Assuming core porosities are equal to DMRP ($\Phi_{core} = DMRP$) which is the gas corrected porosity.

The equation (5) can be written in the following form.

$$\frac{\phi_{Core}}{\phi_{NMR}} = A * \frac{\phi_D}{\phi_{NMR}} + B \dots\dots\dots (6)$$

It is the linear equation intercept at B value and the slope is equal to the A value.

The following plot (Fig-1) represents this equation. Note that at $S_{gxo}=0$, the pores is completely filled with liquid (mud filtrate and irreducible water) so the NMR porosity reading and density-porosity should be correct and both should equal to core porosity. As a result, the trend line of equation (6) should intersect at point (1, 1) as a control point, where $\phi_{Core} / \phi_{NMR} = \phi_D / \phi_{NMR} = 1$. Fluid density for apparent Φ_D estimation is assumed to be of 0.9g/cc, which is a combination between formation water density and mud filtrate density (OBM).

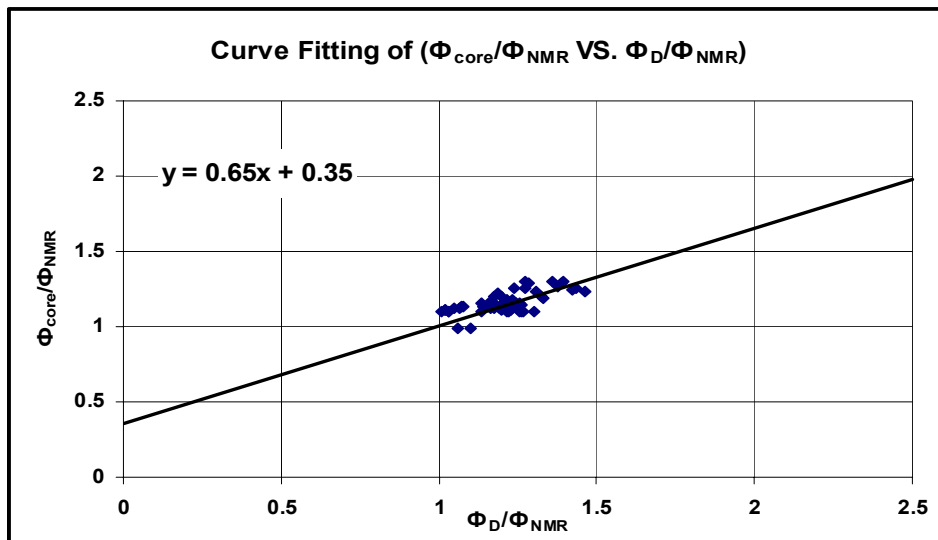


Fig-1: Φ_{core} / Φ_{NMR} VS. Φ_D / Φ_{NMR}

The resulting trend line has a slope of A=0.65 and intercepts the Y axis at B=0.35
 The DMRP porosity transform result from above calibration is as follows;

$$DMRP = 0.65 * \phi_D + 0.35 * \phi_{NMR}$$

RESULTS

For comparison, the fluid density RHOF of 0.82 gr/cc is calculated from bulk density (RHOB)- Φ_{core} cross-plot (Fig-2) in well D7 and then used for porosity calculation from density model for the three wells D7, D18 and D13. The results show good match in D7 as expected, but it is over estimated in both D13 and D18 wells as a result of different pore types which affect the invasion profile and gas effect on density log response.

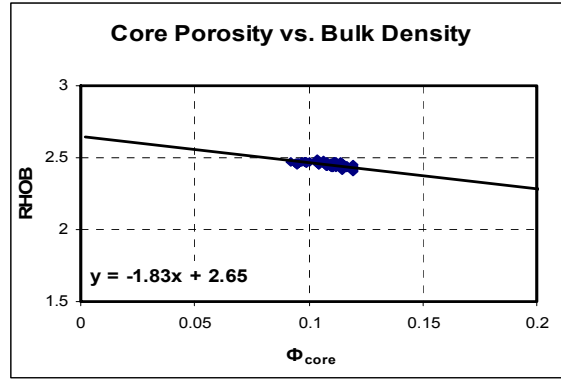


Fig-2: Bulk Density vs. Core Porosity

The results of applying DMR transform after calibration for our reservoir of interest, D7 well facies 1, shows a very good match between DMRP gas corrected porosity and core porosity (Fig 3). These corrected porosities can be used in conjunction with Timur-Coates equation to estimate accurate permeability in gas bearing formations. The DMR method has the advantage of avoiding the use of fluid density and gas hydrogen index (HI) at reservoir condition for gas correction. Another advantage is that we can increase logging speeds as we do not need full polarization for gas.

The same DMRP transform was applied in other wells with different facies, D18 of facies II (moderate grain size and low clay minerals) and D13 of facies III (clean sand and courser grain size). The results also show very good match between DMRP and core porosities in both wells (Figures 4& 5). So the same DMRP transform is valid for the 2 other facies in the massive sand section. As a result it is considered being an independent facies porosity model, at least in the Obaiyed field.

The following figures (3, 4, 5) present porosity calculations from density (PHID) and DMRP porosity for three different facies in three different wells (D7, D18 and D13) with gas bearing sand using same RHOF and DMR transform in well D7 respectively. Gamma ray and Caliper curves are shown in the first track (GR&CALI), second track shows depth in meters, the third one is resistivity, the fourth one is Neutron density, the fifth track shows comparison between core porosity (C_Por), porosity from density (PHID) and NMR porosity (NMR_Por), the sixth track shows comparison between DMRP and C_Por, the seventh track shows saturations of Gas (green shadow) and water (blue shadow) and the last track shows core permeability in mD which represents sand quality changes (Facies).

Root of Square Error Calculations

Wells		D7	D18	D13
Root of Square Error	PHID	0.79	1.08	2
	NMR_Por	1.48	1.54	3.3
	DMRP	0.55	0.54	0.61

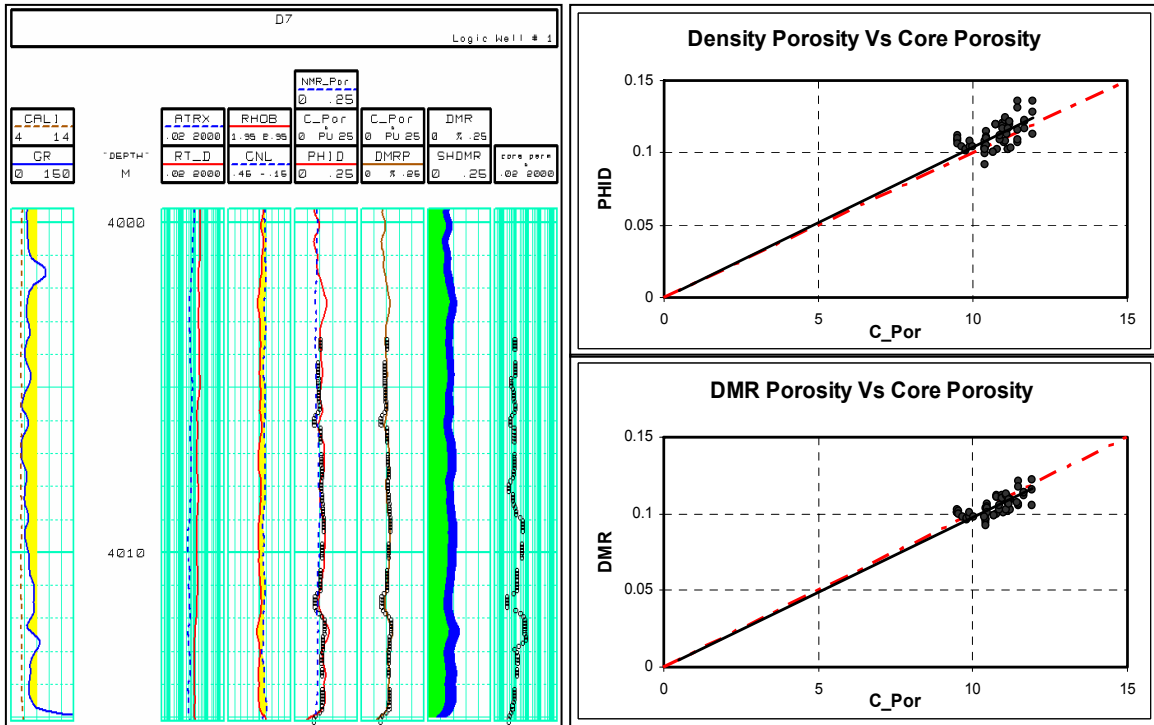


Fig-3: on the right hand shows PHID, NMR_Por and DMRP curves with other normal log, left hand shows PHID and DMRP correlation with core porosity in D7 (Facies I) well.

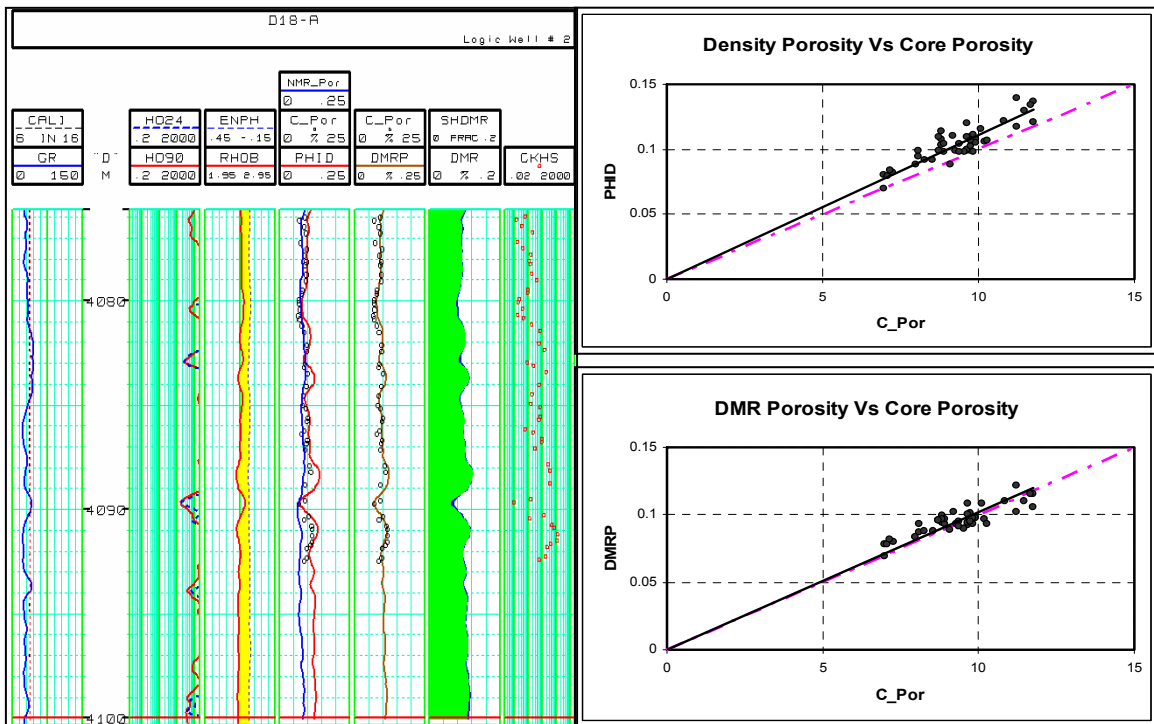


Fig-4: On the right hand shows PHID, NMR_Por and DMRP curves with other normal log, left hand shows PHID and DMRP correlation with core porosity in D18 (Facies II) well.

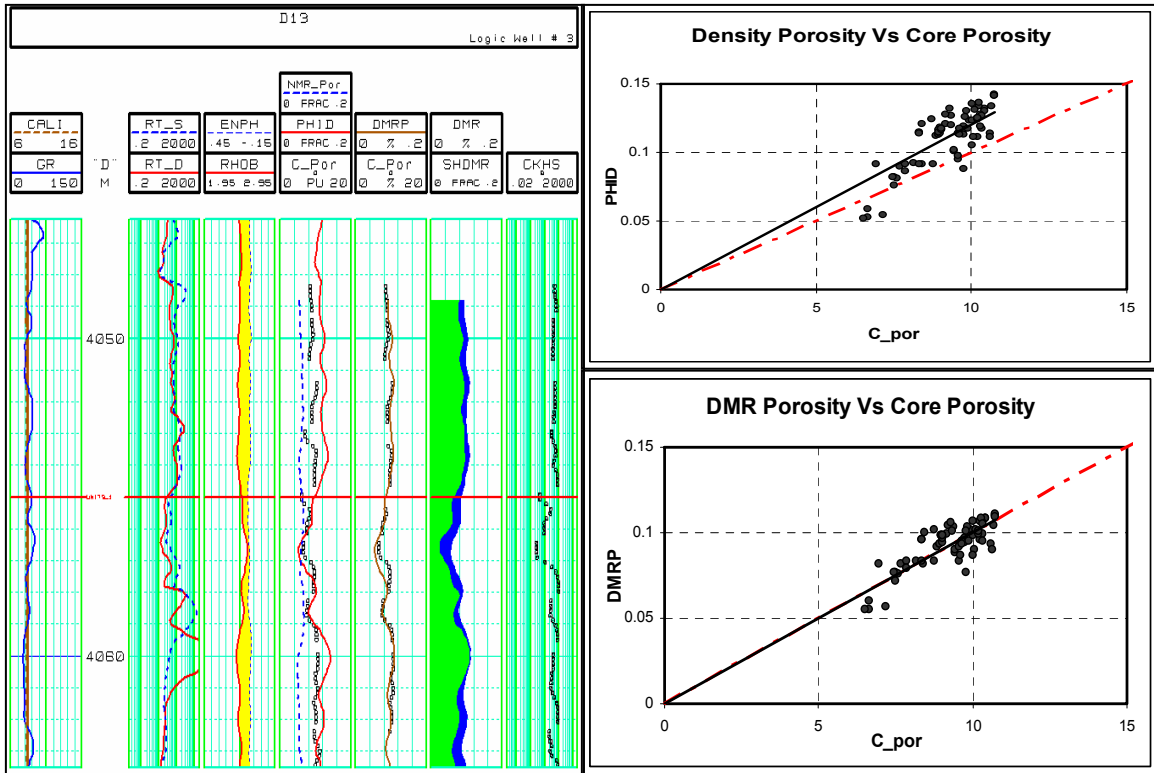


Fig-5: On the right hand shows PHID, NMR_Por and DMRP curves with other normal log, left hand shows PHID and DMRP correlation with core porosity in D13 (Facies III) well.

CONCLUSION

- DMR porosity method is an easy and robust tool for gas corrected porosity because it depends on a mathematical derivation. It combines two tools responses in one simple transform.
- DMR porosities show much better match with core porosity because unknowns presented by RHOF and HIG are both are eliminated in the DMRP transform.
- NMR porosity in combination with density is a very good tool for gas corrected total porosity calculations and is independent of facies as recognized in Facies I, II and III.

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