ASSESSMENT OF UNCERTAINTY IN POROSITY MEASUREMENTS USING UNR AND CONVENTIONAL LOGGING TOOLS IN CARBONATE RESERVOIRS

BY

HAMAD SALMAN ALKHARRAA

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DEANSHIP OF GRADUATE STUDIES

This thesis, written by **HAMAD SALMAN ALKHARRAA** under the direction his thesis advisor and approved by his thesis committee, has been presented and accepted by the Dean of Graduate Studies, in partial fulfillment of the requirements for the degree of **MASTER OF SCIENCE IN PETROLEUM ENGINEERING.**

Dr. Mohamed Mahmoud
(Advisor)

Dr. Mahmoud Doklah
(Co-Advisor)

Dr. Abdullah Sultan
(Member)

Dr. Gabor Korvin
(Member)

Dr. Taha Okasha
(Member)

Dr. Abdullah Sultan
Department Chairman

Dr. Salam A. Zummo
Dean of Graduate Studies

19/5/13
Date

This work is dedicated to my parents

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LIST OF ABBREVIATIONS

Bo	:	Static magnetic field
B1	:	Oscillating magnetic field
Mo	:	Equilibrium value approached by the proton magnetization
TE	:	Echo spacing, milliseconds.
$\mathbf{T_1}$	:	Longitudinal relaxation, seconds.
$\mathbf{T_2}$	:	Transverse relaxation time, seconds.
$\boldsymbol{\phi}$	**:**	Porosity, fraction
$\boldsymbol{\phi_e}$	**:**	Effective porosity, fraction
$\boldsymbol{\phi_T}$	**:**	Total porosity, fraction
$\mathbf{S_w}$	:	Water saturation, fraction
$\mathbf{S_{wi}}$	:	Initial water saturation, fraction
N	:	Oil in Place, bbl
A	:	Drainage area, Acre
H	:	Average net pay thickness, ft
$\mathbf{\Delta t_{log}}$	:	Reading value from sonic logging tool in, µsec/ft
$\mathbf{V_{ma}}$	:	Velocity of matrix mineral, ft/ µsec
$\mathbf{\Delta t_{ma}}$	:	Transit time of matrix mineral, µsec/ft
$\mathbf{\Delta t_f}$	:	Transit time of saturating fluid in, µsec/ft
$\boldsymbol{\rho_f}$	:	Fluid density, g/cc
$\boldsymbol{\rho_b}$	:	Bulk density, g/cc

$\boldsymbol{\rho}_{\mathbf{ma}}$	:	Matrix density, g/cc
$\mathbf{R_w}$	:	Formation water resistivity, Ω.m
$\mathbf{V_{cl}}$	:	bulk volume of clay, ft^3
$\mathbf{R_t}$	:	True formation resistivity, Ω.m
$\mathbf{R_{cl}}$	:	Resistivity of dispersed clay, Ω.m
FFI	:	Free Fluid Index, fraction
BVF	:	Bulk Volume Fluid, fraction
CBW	:	Clay Bound Water, fraction

ABSTRACT

Full Name : Hamad Salman Al-Kharraa

Thesis Title : Assessment of Uncertainty in Porosity Measurements using NMR and Conventional Logging Tools in Carbonate Reservoirs

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Porosity is a critical volumetric parameter used to estimate the reserves for oil and gas reservoirs and as an input for reservoir simulation. Porosity can be classified into effective porosity (interconnected pores) and ineffective porosity (isolated pores) while total porosity (ϕ_T) is defined as the sum of effective porosity and the porosity associated with clay bound water. In clean formations, total porosity is equal to effective porosity, whereas in shaly formations it must be corrected for clay effect. Formation porosity can be determined using several methods. These methods include: measuring actual porosity in the core laboratory, Computerized Tomography (CT) scan, neutron-density logging, sonic tools and Nuclear Magnetic Resonance NMR logging tools. The NMR logging is unique compared to all other methods since it is independent of the reservoir lithology. It can be used to estimate the reservoir porosity directly without the knowledge of matrix lithology. On the other hand, conventional logging such as neutron-density and acoustic depend strongly on lithology which might yield incorrect porosity measurement. Several studies have been conducted to estimate porosity for both sandstone and carbonate reservoirs using different logging tools, however, determining porosity is a challenge in complex and unconventional lithologies. In sandstone, the presence of shale and clay minerals will affect the response of all porosity tools. Carbonate is even more complicated than sandstone due to its heterogeneity and triple porosity system (pores, vugs, and fractures). In addition, the assessment of porosity measurements accuracy using NMR logging was considered in this study. An attempt was made to develop an empirical correlation from NMR data to obtain reliable porosity estimation. In this work, case studies were presented using NMR logging tool to show how NMR reduces the uncertainty of porosity measurements in carbonate reservoirs compared to other conventional logging tools, which improve reserves estimation. The study also showed the effect of impurities in the carbonate formation porosity measurements by conventional and NMR logging methods compared to stress core porosity by graphical means. Results of this study showed that a clear criterion to divide the formations into dolomitic and clean limestone formation should be established to get more accurate result. In the dolomitic formation, Neutron-Density showed the least AARE of 40.2% compared to 84% for the NMR tool and 174% for the sonic tool. However, for clean limestone formation NMR tool was the most accurate tool with AARE of 10% compared to 14.3% for N-D tool and 42.3% for sonic tool.

ملخص الرسالة

الاسم الكامل: حمد سلمان الخراع

عنوان الرسالة: عنوان الرسالة:تقييم أوجه عدم التيقن في القياسات المسامية باستخدام الرنين المغناطيسي ومعدات التسجيل التقليدية في المكامن الجيرية

التخصص: هندسة نفط

تاريخ الدرجة العلمية: رجب ١٤٣٤

تعتبر مسامية الصخور من الخواص المهمة في تقدير مخزونات النفط والغاز وبرامج محاكاة المكامن. ويمكن تقسيم المسامية إلى المسامية الفعالة والمسامية المعزولة بينما تعتبر المسامية مسامية كلية في حالة مكمن الحجر الرملي وهي عبارة عن المسامية الفعالة وتلك اللتي تحتوي علي المياه المكونة للمعادن الطينية. وهناك عدة طرق لتحديد مسامية المكامن مثل:القياسات المخبرية والمسح الطبقي بأشعة (س) وتسجيلات الابار (الكثافة النيترونية-الكثافة الصوتية-الرنين المغناطيسي).
ويعتبر تقييم المسامية باستخدام الرنين المغناطيسي من أفضل الوسائل لتعيين مسامية المكامن مقارنة بالوسائل الأخرى لأنها لاتعتمدعلى نوعية الصخور والمعادن المكونة لها. وقد تمت عدة دراسات لتقييم مسامية صخور المكامن الرملية والجيرية باستخدام معلومات تسجيل الابار. ووجود معادن الكلي في الصخور الرملية قد يؤثر على اجهزة تسجيل الابار والمعلومات المصاحبة لتقييم المسامية. على الجانب الاخر فان تقييم مسامية الصخورالجيرية تحتاج لكثير من التحديات وذلك لطبيعة التركيب المعقد والغير متجانس وكذلك لوجود فراغات مثل الشقوق وبقايا الكائنات الدقيقة.في هذه الدراسة تم استخدام أكثر من ٣٠٠ عينة صخرية مختارة من أحد المكامن الجيرية لقياس خاصية المسامية. وقد استخدمت جميع الوسائل المعروفة من الرنين المغناطيسي والكثافة النيترونية والصوتية والمسح الضوئي بأشعة (س) لحساب وتقييم مسامية المكمن على ان تقارن مع قيم المسامية الناتجة من القياسات المخبرية نظرا لدقتها العالية .كما أجريت في هذه الدراسة الحسابات الاحصائية اللازمة لتقييم قيم المسامية باستخدام الطرق المختلفة.
وقد أثبتت النتائج ان استخدام الرنين المغناطيسي يعتبر من أفضل الوسائل لتقييم المسامية ولكن تبين أن وجود الدولوميت يؤثر بشكل واضح على قيم المسامية. وقد تم تطوير معادلة رياضية لحساب المسامية لتصحيح قراءات الرنين المغناطيسي في وجود الدولوميت ومقارنتها مع قيم المسامية الاصلية بالاستعانة بالتحليل الاحصائي والرسم البياني.

CHAPTER 1

INTRODUCTION

Porosity (ϕ) is a dimensionless parameter, defined as the ratio of pore volume filled with fluid (V_p) to the bulk volume (V_b). Porosity is a critical volumetric parameter used to estimate the reserve for a given reservoir and it can be used as an input for reservoir simulation as well. In addition, porosity can be classified into two types, effective porosity (interconnected pores) and total porosity (connected and isolated pores). Total porosity (ϕ_T) is defined as the sum of effective porosity and clay bound water (CBW). In other words, total porosity obtained from conventional logging tools will be equal to effective porosity in the absence of clay and while it is not the case when clay is present.

There are several methods used to estimate porosity of the formation. These include: measuring actual porosity in the core laboratory, computerized tomography (CT) scan, neutron-density logging, sonic tools, and NMR logging tools. All conventional logging tools (neutron-density and sonic logging tools) are strongly dependent on lithology, whereas NMR logging tool is independent of lithology.

For clean formation porosity from sonic logs can be estimated using Wyllie Time–Average equation (1958)[7] as follows:

$$\phi = \frac{\Delta tlog - \Delta tma}{\Delta tf - \Delta tma} \tag{1}$$

Where; (Δt_{log}) is the acoustic travel time that can be read from sonic logging tool in µsec/ft; (Δt_{ma}) is acoustic travel time of the rock matrix in µsec/ft and (Δt_f) is acoustic travel time for fluid in µsec/ft .

Table 1 lists typical values of the signal velocities in different matrices and travel time values for common lithology while NMR porosity calculation does not require having these values to obtain the porosity.

Table 1: Transit times and sonic velocity values for or different lithologies

Lithology	V_{ma} (ft/sec)	Δt_{ma} (µsec/ft)
Sandstone	18000	55.5 or 51
Limestone	21000-23000	47.5
Dolomite	23000	43.5
Anhydrite	20000	50

In addition, knowing the lithology of the logged section, porosity from density log can be obtained by the following equation:

$$\phi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \quad (2)$$

Where, (ρ_b) is formation bulk density in g/cc,(ρ_{ma}) is matrix density in g/cc and (ρ_f) is fluid density in g/cc. Matrix density values for different common lithologies are shown in **Table 2** where NMR porosity calculation doesn't require having these values to obtain the porosity. This method deploys values of matrix and fluid densities for pure formations and fluids. Moreover, assuming a fresh water density in a formation already invaded is a wrong assumption that carries inaccurate measurements and calculations. The matrix density for pure carbonate formations can be considered as the ideal case; however, the matrix density will vary if dolomite and clay are present which will strongly affect the porosity measurements. For example, a formation that has 30% volume of dolomite is usually considered as a pure carbonate formation which is an incorrect assumption. These inaccurate assumptions add and accumulate the error throughout the porosity calculations.

Table 2 : Matrix density for or different lithologies

Lithology	ρ_{ma} (g/cc)
Sandstone	2.65
Limestone	2.71
Dolomite	2.85
Anhydrite	2.98

Unlike Gamma Ray, NMR tool is a non-radioactive tool as it does not create any form or type of radiation. NMR is a resonance phenomenon which works in high powered magnets. Also, it provides a number of important petrophysical parameters that enrich our understanding of the reservoir such as total porosity, free and bound fluid, permeability, tar identification, gas detection, viscosity, and water saturation-bound fluid. NMR tool is unique and different than conventional logging tools since it is independent of lithology. It measures only the amount of hydrogen contained in the fluid (Stefan M. et al., 1998).

The idea of NMR was derived from the Magnetic Resonance Imaging (MRI) which is one of the most valuable clinical diagnostic tools in health care today as shown in **Figure 1**. The patient is placed in the whole-body compartment of an MRI system, magnetic resonance signals from hydrogen nuclei at specific locations in the body can be detected and used to construct an image of the interior structure of the body. Looking again at the same **Figure 1**, the light areas represent tissues with high fluid content like brain while the dark areas show the tissues with minimal fluid content such as bones.

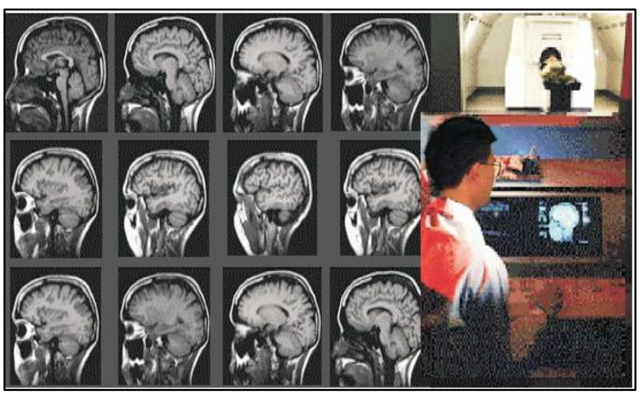

Figure 1: Brain tissues diagnostic using MRI.
(Refernce: see NMR logging principles & applications)

In 1991, logging company, NUMAR, came up with a brilliant idea with same MRI concept, but rather than placing the object in the middle of the medical instrument, the tool was placed in the center of the well borehole as shown in **Figure 2**.

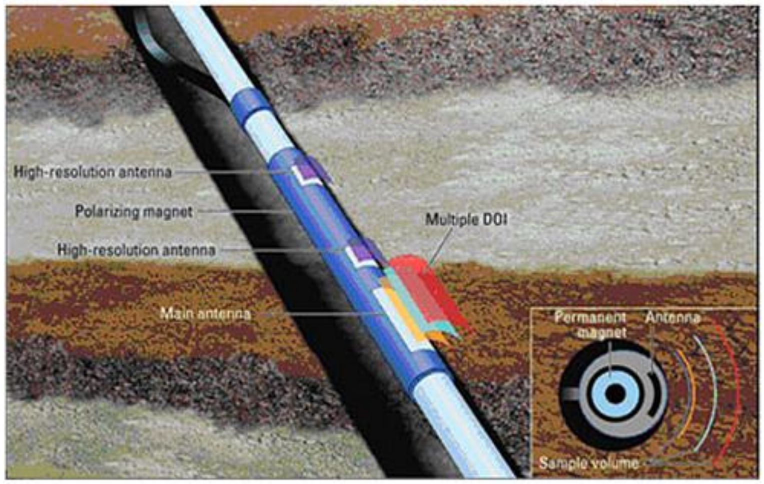

Figure 2: NMR logging tool
(Reference: see NMR logging principles & applications)

One of the main applications of NMR is in-situ total porosity measurement. All conventional logging tools depend on lithology such as neutron density and acoustic logging tools which result in different readings from core laboratory porosity measurement. Hydrogen density (number of protons per unit volume) can be used as an indicator to the total porosity. Both NMR and Neutron tools are influenced by hydrogen density. However, NMR has two critical advantages over Neutron tools. First, NMR tools detect only the amount of hydrogen in the fluid, whereas Neutron tools are influenced by several earth materials such as hydrogen and chlorine. Second, Neutron tools which are affected by hydrogen in lattice clay mineral will show high reading in shale formations. Gas-bearing zones are identified when total NMR porosities read much less than density-derived porosities. On the other hand, since NMR is independent of lithology, it will detect only hydrogen in the fluid from which true total porosity will be measured (Miller 1990).

The number of hydrogen atoms per unit volume divided by the number of hydrogen atoms per unit volume of pure water at surface conditions results in a value defined as the hydrogen index (HI) which is a key factor to estimate NMR porosity. NMR porosity is calibrated to a known volume of water. The signal received from the logged formation is compared to the calibrated water signal, and the porosity can be estimated by integrating the area under the signal curve. Pore size geometry affects the decline of the signal received and as a result, the porosity depends on the pore size, the smaller the pore the faster the decline is, **Figure 3**. For small pores, some of the signals would not be detected which named as missing porosity. As the molecular weight gets heavier (Tar), a portion of NMR signals decays too fast to be detected by NMR tool and as a result, reservoir properties in this section will be underestimated.

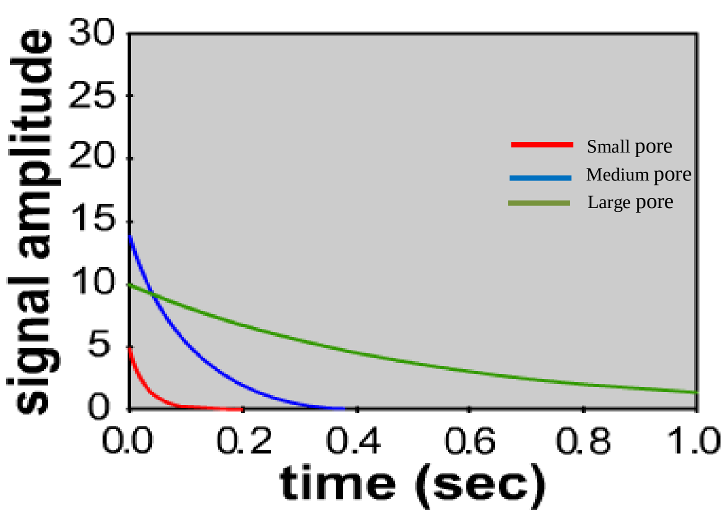

Figure 3: Pore size versus decline rate

In sandstone the typical pore volume model is composed of four different components which are: clay bound water (CBW), capillary bound water (CAP), free water, and hydrocarbon as shown in **Figure 4**.

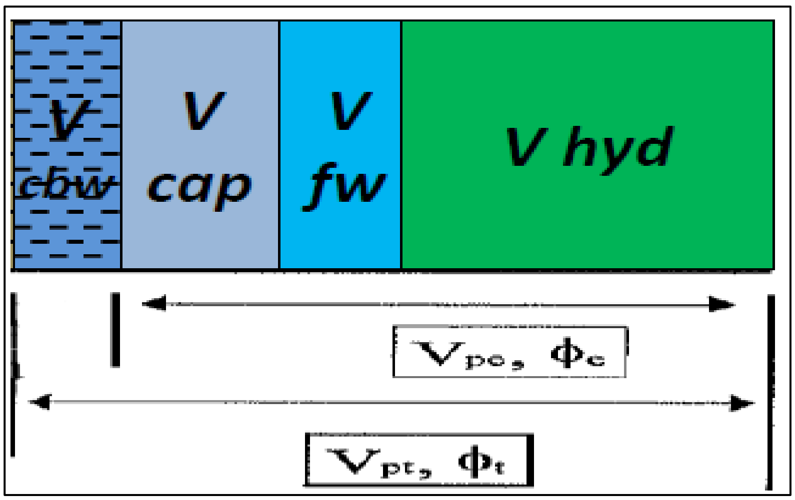

Figure 4: Four components pore volume

Clay bound water is the water trapped by lattices of clay and considered as ineffective porosity. Although BVF (Bulk Volume Fluid) is non-producible as the CBW, BVF water is bounded to the surface of matrix by capillary forces and wetting phase phenomena and it is included with effective porosity region.

Resistivity logs can be used to estimate water saturation (S_w) using Archie law. However, resistivity-based S_w is a combination of CBW, BVF, and free water and only the effective porosity is used to calculate hydrocarbon reserves; Archie S_w must be refined for clay effect using mathematical equations.

One of the conventional interpretation techniques is Simandoux model (1963)[22]. He proposed a mathematical equation that incorporates the correction using shale volume and resistivity. The formula is given by:

$$Sw = \left(\frac{0.4\ Rw}{\Phi^2}\right)\left(\frac{-Vcl}{Rcl} + \sqrt{\frac{Vcl^2}{Rcl} + \frac{5\Phi^2}{RtRw}}\right) \qquad (3)$$

Where, (R_w) is formation water resistivity, (V_{cl}) is bulk volume of clay, (R_t) is true formation resistivity and (R_{cl}) is resistivity of dispersed clay.

Utilizing one of mathematical techniques might result in many uncertainties in addition to their inability to determine the volume of movable and non-movable fluids. On the other hand, NMR tools have the advantage of finding the volume of clay and other volumes as shown in **Figure 4** it is easily and precisely by knowing only the T_2 cutoff.

In carbonates the interpretation is more challenging than sandstone due to broad range of pore size (Micro, Meso, and Macro) **Figure 5**.

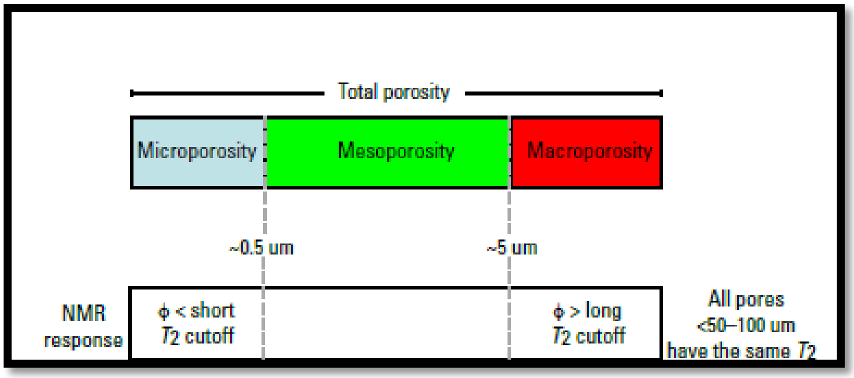

Figure 5: Carbonate porosity distribution of NMR image

Knowing moveable and non-movable fluids is essential to optimize reservoir development plans. NMR signals can be inverted to spectrum to differentiate between movable and irreducible fluids. Cutoff values that are established using core plugs and bench top NMR measurement in the laboratory are used to divide NMR T_2 spectrum to moveable and non-movable regions **Figure 6**.

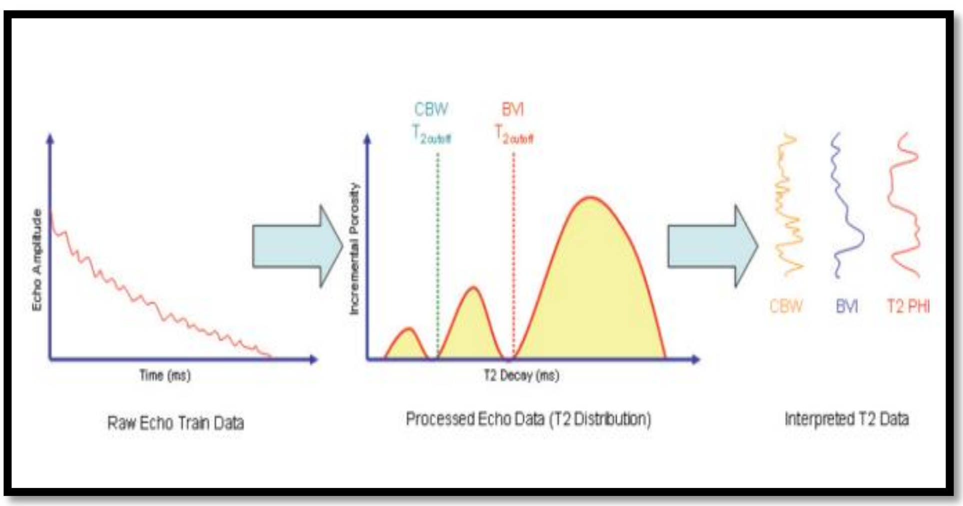

Figure 6: Moveable and non-movable regions

The physics behind the NMR is related to the response of atomic nuclei to the magnetic fields. Many nuclei have a net magnetic moment (M) and angular momentum or spin.

NMR phenomenon occurs when the nuclei of atoms, with spin property, are placed in a static magnetic field (Bo) and then excited by a radio frequency (RF) magnetic field, **Figure 7**.

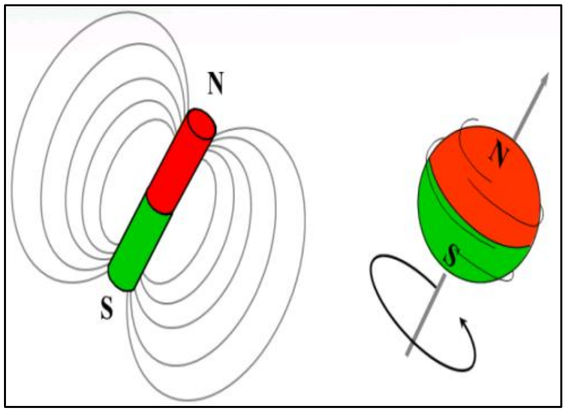

Figure 7: Charged particles with spin

Initially, without an external magnetic field; hydrogen nuclei are randomly oriented with no macroscopic magnetization. After a static magnetic field (Bo) is introduced, Hydrogen nuclei start orienting parallel and anti-parallel to reach equilibrium state with macroscopic magnetization (Mo) due to microscopic difference in parallel and anti-parallel spins. The buildup rate to reach equilibrium state is defined as longitudinal relaxation time, T_1, **Figure 8**. Different fluid types will build up in different rates, and then T_1 carries information about the fluid type, **Figure 9**.

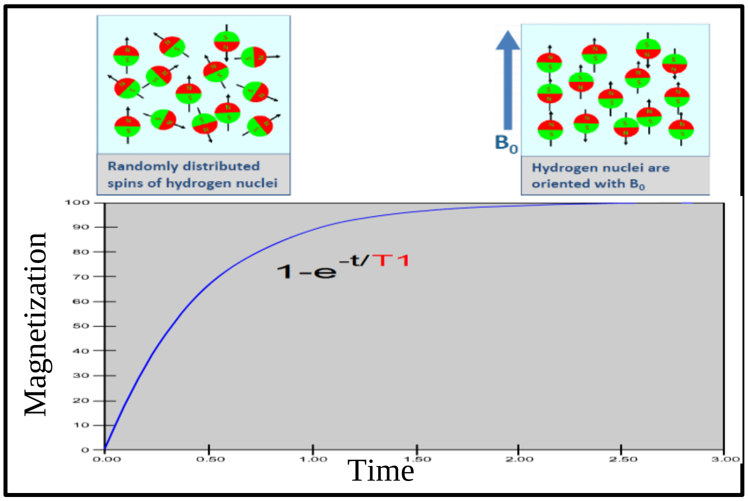

Figure 8: Spins aligning with the static magnetic field Bo

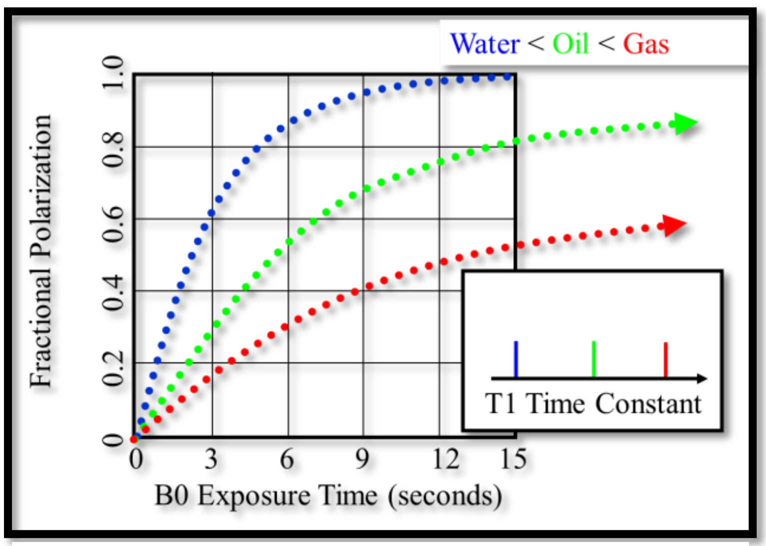

Figure 9: Fluid types versus polarization

After equilibrium state is established, the spins are disturbed by an oscillating magnetic field (B1) perpendicular to the static magnetic field. This causes the spins to move in precession motion. The frequency of this motion is called Larmor-frequency. When B1 field is turned off, the proton population begins to decrease and the net magnetization decreases as a result of that. In this situation, a receiver coil that measures magnetization in the transverse direction will detect a decaying signal. This declining rate of signal is known as the transverse relaxation time, T_2 **Figure 10**. Knowing the distribution of T_2 will lead to better understanding of the reservoir petro-physical properties.

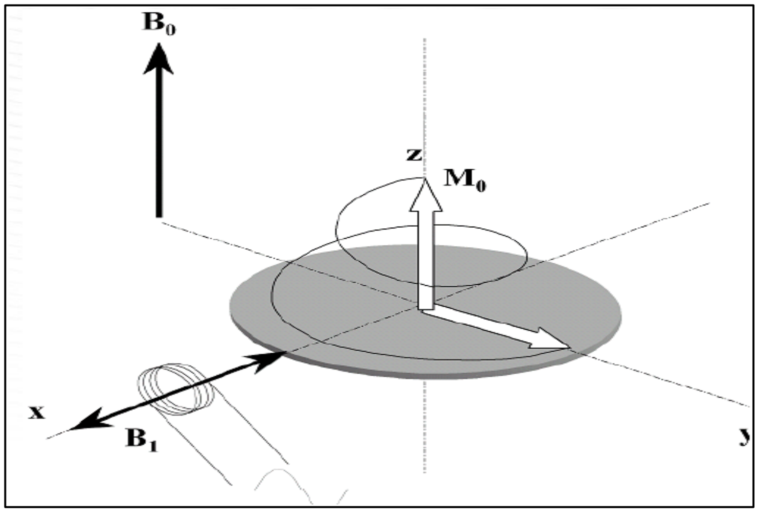

Figure 10: Precession motion for spin

1.1 Statement of the Problem

Carbonate reservoirs have many challenges in petrophysical analysis. Analysis using conventional logging tools (neutron-density and sonic) and core laboratory was conducted to estimate formation porosity. Literature has reported many approaches to estimate formation porosity. Conventional logging tools have limited accuracy due to its associated uncertainty. The conventional tools are greatly affected by lithology, fluid content as shale may cancel gas effect, drilling fluid invasion effect, fracture effect, and the difficulty to analyze triple porosity system due to reservoir heterogeneity. Porosity measurement assessment using NMR tool will show the accuracy improvement in formation evaluation. Accurate porosity measurement is essential to improve the prediction and estimation of reserves and for better reservoir simulation results because initial hydrocarbon in place and reserves are functions of porosity especially if volumetric method is used:

$$N = \frac{Ah\phi(1 - Sw_i)}{B_o} \tag{4}$$

Furthermore, an important input parameter in reservoir simulation is permeability which is dependent to some extent on effective porosity.

1.2 Research Objectives

In this study, a comprehensive comparison was carried out between the available porosity measurement methods (conventional logging tools and NMR logging tool) in two carbonate fields to assess uncertainty in porosity measurements. The results were validated using core laboratory analysis. In addition, porosity measurements accuracy assessment using NMR logging will be considered in this study. An attempt will be made to develop an empirical correlation from NMR data to obtain reliable porosity measurements.

1.3 Research Methodology

Field samples were collected from Arabian carbonate reservoir to perform laboratory analysis. The raw logging data was validated and depth will be matched. Furthermore, porosity values was obtained and interpreted from conventional logging using available cross plots. Moreover, porosity measurements from field NMR logging tool were interpreted and compared to NMR core laboratory measurements. A comparison between conventional and NMR logging tools for porosity estimation was presented against core samples using the statistical methods.

CHAPTER 2

LITERATURE REVIEW

Several studies have evaluated the porosity estimation for both sandstone and carbonate reservoirs using different direct and indirect methods. In the literature, sandstone porosity estimation using NMR has been addressed whereas few investigation studies are carried out for carbonate formations.

Timur[2] (1969) studied the relation between producible porosity and permeability using Nuclear Magnetic Resonance (NMR). He used producible porosity terminology to differentiate between the effective and producible porosities. It is a very important parameter for reserve estimation that is defined as the percentage of movable fluid volume of the bulk volume. Several laboratory measurements such as spin-lattice (T_1) relaxation time, porosity, permeability, and irreducible water saturation were conducted for more than 150 sandstone core samples that have been collected from three different fields. Test data were analyzed to develop an empirical formula that estimates producible porosity. By using Reduced Major Axis (RMA) method, the formula gives a linear relationship between producible porosity and Free Fluid Index (FFI) within 2.9 porosity units (P.U.) standard error and correlation coefficient of 0.93, which indicates an excellent linear fit.

Timur[3] (1972) investigated NMR porosity estimation in carbonate reservoir. The study was done by collecting 100 rock samples from four oil fields in North America. He developed empirical correlation that relates FFI and porosity using RMA analysis method. He concluded that porosity from carbonate reservoir can be estimated accurately regardless of the variation of limestone to dolomite ratio. On the other hand, conventional logs will give inaccurate porosity values due to porosity lithology dependence.

M.N. Miller et al[4].(1990) for the first time introduced spin echo magnetic resonance Imaging Logging (MRIL) measurements while drilling (LWD) without borehole treatment to estimate porosity. MRIL tool was applied into two fields (sandstone and fractured limestone) with borehole full of both oil and water based mud to estimate porosity. By extrapolating signal amplitude at (t=0) and using bi-exponential curve fitting algorithm, porosity is determined. The porosity from MRIL was analyzed and compared to the core porosity and density-neutron log. After taking average of squares for both density- neutron porosity and square root, conventional density-neutron average porosity was estimated. Then, this value was compared with porosity from MRIL tool which showed good agreement. A sample of fractured limestone was analyzed in the laboratory to estimate core porosity and compare it to porosity from NMR. They observed that high free fluid volume is moveable due to low surface relaxation. In addition, they showed that sandstone porosity drilled with Oil-Based-Mud (OBM) gives higher laboratory measurements error compared to water-based-mud (WBM).

Dahai C. et al[5]. (1994) evaluated the porosity measurements in mixed complex carbonate reservoir. Combinable Magnetic Resonance tool (CMR) and conventional logs were run in Glorieta and Clearfork Carbonate in west Texas. They proved that in clean mixed carbonate, the total porosity measured by CMR tool is matched with conventional logs (Neutron, Sonic and Density). However, in silty zones, CMR tool measured only the effective porosity since micro porosity cannot be detected. Also, more than 25 core samples were analyzed and compared to NMR lab porosity. They observed that NMR porosity is higher by 1.4 P.U. on average due to unsuccessful attempts to extract hydrocarbon from cores.

Prammer et al[6]. (1996) discussed the use of NMR to measure clay-bound water and total porosity. Clay samples were taken and studied and results showed a linear relationship between the transverse of relaxation time and water content. At that time, tools were not able to detect relaxation times faster than 3-5 ms; so the porosity measurement gave effective porosity instead of total porosity. An improvement in the logging tool is needed to be able to detect and report the clay-bound water effect. As a result, the logging tool will be independent of lithology. They presented several examples where NMR logging tool gave more accurate porosity measurements than those of neutron and density based logs when compared with laboratory core data.

Logan et al[7]. (1998) studied the porosity estimation in carbonate reservoirs in west Texas. The objective was to determine the formation porosity in San Andres. Formation lithology was gypsum and dolomite. Core samples were taken and measured in the laboratory and CMR logging tool and compensated neutron log/lithodensity log (CNL/LDT) were run to evaluate porosity of the formation. They observed that CNL/LDT read higher than porosity from CMR tool as a result of gypsum effect. They ran borehole compensated sonic log (BHC) to estimate the volume of gypsum in the formation. Then, they generalized empirical correlation from (BHC/CNL/ LDT) logs to estimate porosity. They compared the porosity from cores, empirical correlation, and CMR. They concluded that the empirical correlation closely matched the porosity measured by CMR.

Stefan M. et al[8]. (1998) compared the porosity measured from NMR (MRIL), neutron-density tools and laboratory core samples. The study was applied for three sandstone fields named offshore Louisiana shelf (Oil Well), San Joaquin Basin (Gas Well), and Western desert (Gas Well). By comparing the MRIL and conventional logs, they observed a perfect match between NMR porosity, density porosity and cores, where neutron porosity showed higher value compared to the core porosity due to the shale effect to the neutron tool. For both gas wells, neutron/density tool did not show crossover reading, since it shows high reading. When NMR tool was run, it proved that the cause of higher neutron tool readings is presence of the clay. They concluded that, NMR porosity can replace the conventional porosity in formation evaluation, since NMR porosity is independent to lithology. In addition, MRIL can investigate the clay location while conventional logs cannot.

Daniel T. et al[9]. (1999) evaluated the NMR porosity in sandstone and carbonate blocks. The NMR porosity was compared against the laboratory core porosity. The results of the experiment showed a perfect match with nearly 0.5 P.U. error. They studied effectiveness of pore mineralogy and pore geometry in porosity estimation. They concluded that in sandstone, the T_2 decay rate will be faster than in carbonate formation. As a result, knowing the decay rate in both sandstone and carbonate is mandatory for porosity interpretation. Also, they observed that, large pores take longer time to decay whereas smaller pores decay faster. They categorized three porosity types in shaly sand formation, porosity from clay bond water (CBW) interpreted with T_2 decay less than 3.5 ms, whereas effective porosity took more than 3.5 ms. However, full T_2 spectrum is needed to derive the total porosity of the formation. Moreover, based on T_2 cutoff the effective porosity can be divided into bulk volume capillary bound water (BVF), and bulk volume free fluid (FFI).

Hamada et al[10]. (2007) has combined the use of NMR with other open hole logs in attempt to improve porosity and other properties estimation. They came up with density-magnetic resonance porosity to take into consideration the gas presence and variations in invasion profile and vertical heterogeneity. Also, they found that it is possible to estimate the correct porosity compared to actual core porosity measured in the laboratory regardless of the lithology type. One advantage of their approach is that there is no need to use fluid density and gas hydrogen index to correct for gas presence. Also, NMR logging tool can be run faster in the case of gas well since gas is more polarized than other fluids.

Ehigie S.[11] (2010) discussed porosity measurements from different logging tools NMR, CMR and MRIL. He stated that, using MRIL tool in elliptical and huge breakout affects porosity measurements. However, it is a centralized type device which can "see past" borehole rugosity. On the other hand, CMR tool which is a pad-tool is not affected by the sole size, but it is affected by borehole rugosity. He mentioned that, environmental factor can affect NMR data and may give incorrect values compared to the actual porosity. As a result, he recommended that, an integration of conventional logging tools with NMR tool will give a better estimation of porosity measurements.

CHAPTER 3

DATA DESCRIPTION AND VALIDATION

3.1 Data Description

In this study, 335 samples were obtained from two carbonate fields in Saudi Arabia to assess the uncertainty in porosity measurements using different techniques. Porosity measurements have been obtained from Neutron-Density (N-D), Sonic and NMR logging and compared with the laboratory measured core porosities. A description of the data utilized in this comprehensive study is shown in **Table 3**. It is clearly noticed that the average porosity from NMR logging of 0.13 has an absolute error of 0.82% from the core sample. This shows a good match between the NMR and core sample porosity measurements which gives hint of thinking of NMR to be our main focus in this study. Moreover, a standard deviation (SD) value is a measure of the desperation of a set of data from its mean, the more scattered the data the higher the deviation value. As it is shown in **Table 3** NMR porosity logging data gives the least SD.

Table 3 : Data description of porosity measurement techniques

Porosity Method	Minimum	Maximum	Mean	SD
Stress Core Laboratory	0.0061	0.2971	0.1344	0.0887
Neutron-Density Logging	0.0101	0.2763	0.1074	0.0890
Sonic Logging	-0.0458	0.2495	0.0722	0.0972
NMR logging	0.0134	0.2950	0.1262	0.0813

CHAPTER 4

RESULTS AND DISCUSSION

4.1 Statistical Error Analysis:

In this study, several statistical parameters were used to examine, diagnose, and visualize the porosity measurements accuracy referenced to the stressed core sample porosities. Accordingly, porosity measurement methods will be evaluated against these statistical parameters. Four statistical parameters are applied as follows: Average absolute percent relative error (AARE), maximum absolute percent relative error (E_{MAX}), relative error standard deviation ($E_{St.D}$), correlation coefficient (R) and cross plot graphical analysis are conducted as shown in **Table 4** to evaluate the accuracy of different porosity measurement methods.

Table 4: Results of porosity measurement techniques

Porosity Method	AARE	E_{MAX}	$E_{St.D}$	R
Neutron-Density Logging	23.4	251.9	29.8	0.9532
Sonic Logging	88.7	813.4	122.2	0.6636
NMR logging	35.9	688.1	78.3	0.9526

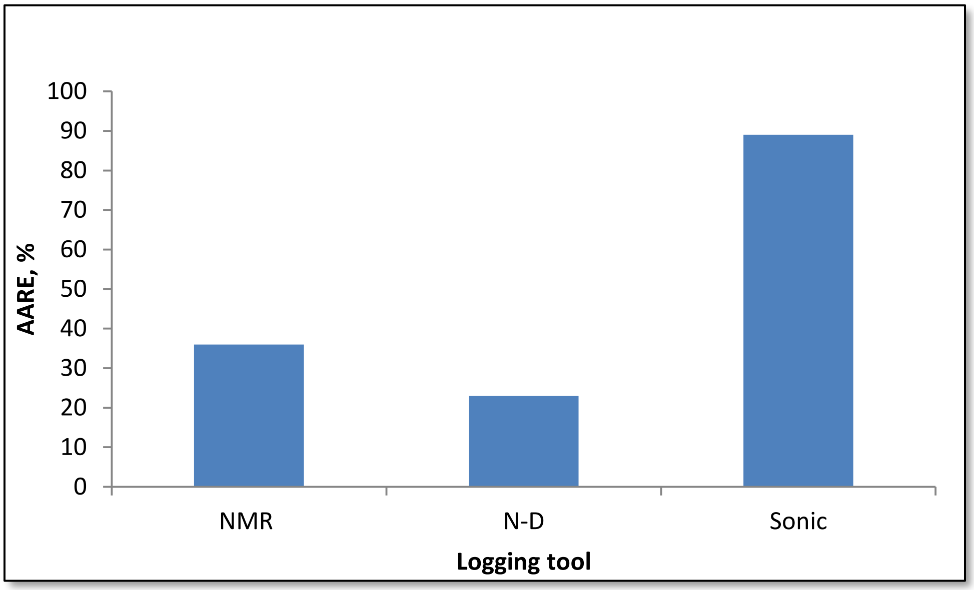

Figure 11: AARE for different tools in mixed lithology

As shown in **Table 4**, N-D and NMR porosity gives most accurate results based on correlation coefficient with approximately 0.95 whereas sonic porosity shows the lower R of 0.6636. Applying further statistical analysis, N-D shows even lower AARE compared to NMR by more than half. In addition, sonic porosity has the highest AARE of 88 % among all the porosity methods as shown in **Figure 11**. From the above table, N-D logging displays the best accuracy in terms of AARE, R, $E_{St.D}$ and E_{MAX}. However, sonic logging is clearly the least accurate method because it treats the formation as if it is a pure limestone without the consideration presence of other mineralogy as the value of Δt_{ma} acoustic travel time of the rock matrix and Δt_f acoustic travel time for fluid were assumed for pure limestone formation. For limestone formation the Wyllie Time–Average equation can be used to estimate porosity from sonic logs.

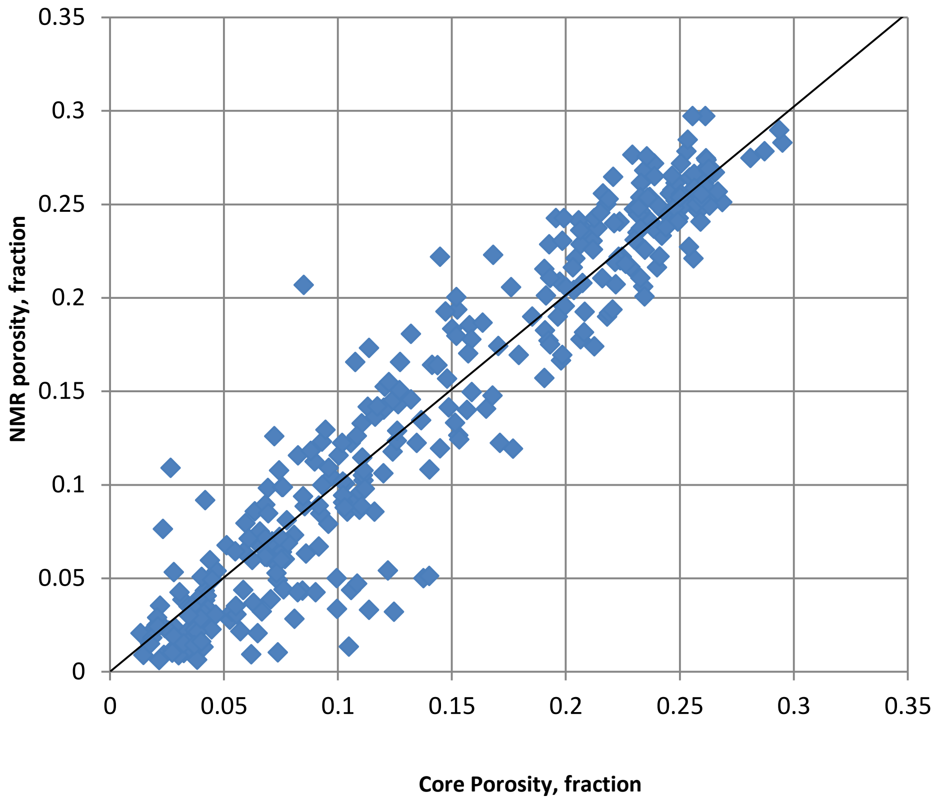

Figure 12: NMR porosity Vs. core porosity

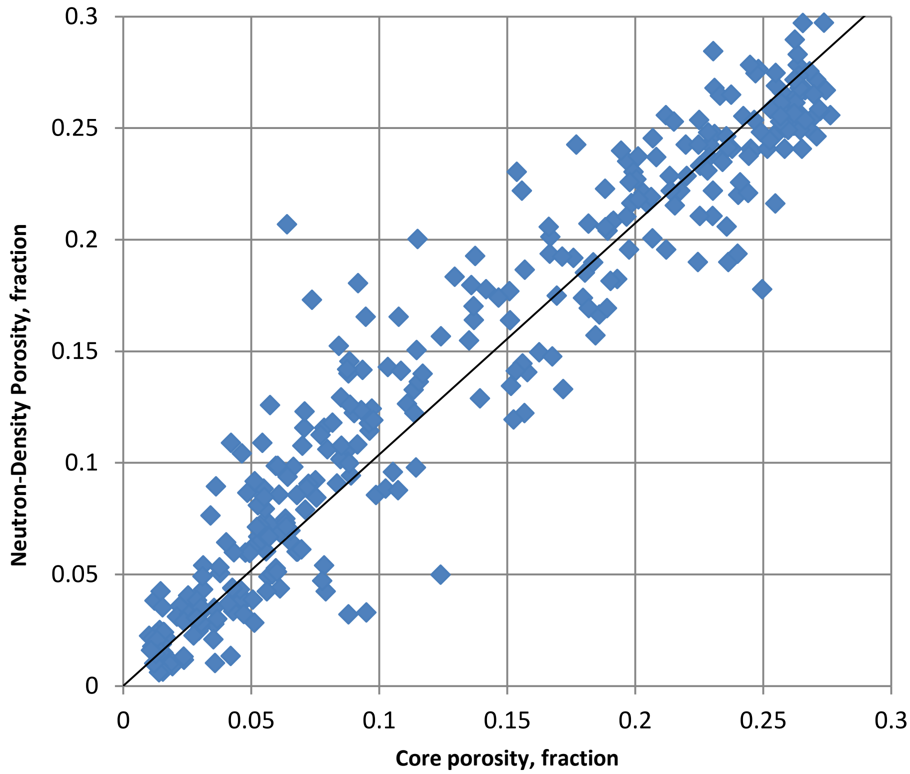

Figure 13: Neutron-Density logging porosity Vs. core porosity

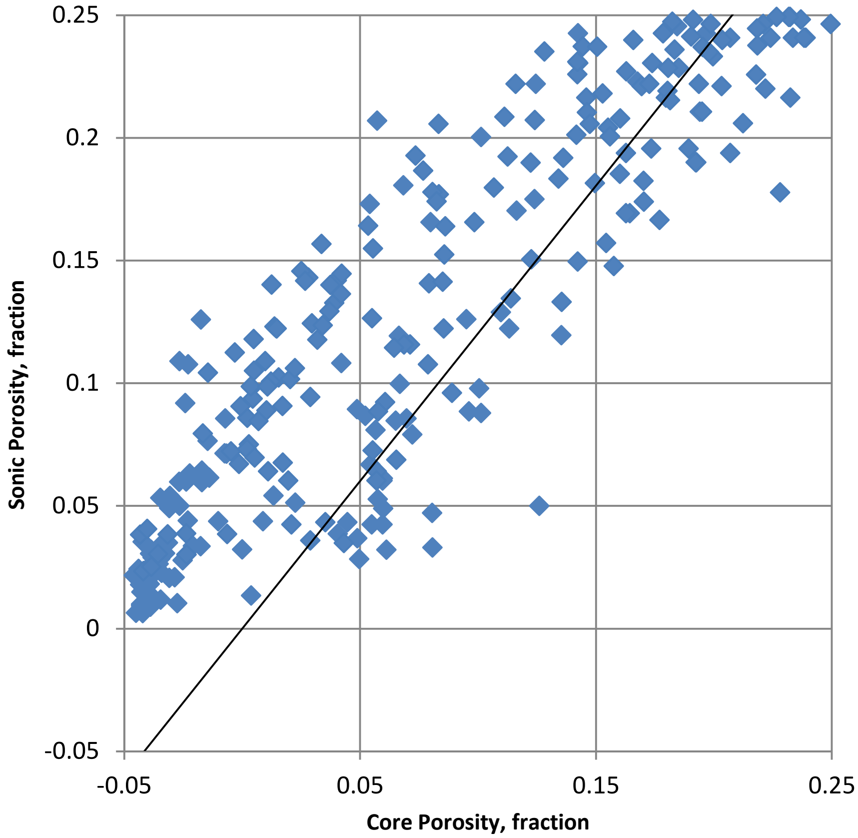

Figure 14: Sonic logging porosity Vs. core porosity

After studying NMR data, it is clear that there is some degree of deviation from the actual porosity data given that it is lithology independent. With further investigation it is observed that this deviation is always found as dolomite percentage increases. This deviation is attributed to the high level of compaction of dolomite and, hence, smaller pores. With formation of small pores, the T_2 decay will be faster and the tool will not have adequate time to capture the T_2 spectrum. Therefore, it will not be able to detect the porosity accurately. This observation is confirmed using CT scan and NMR on the core sample in the laboratory to prove this high level of compaction as it is shown in **Figure 17**. As a result porosity will be under estimated by NMR logging. The data was classified based on the dolomite percentage into two classes: clean limestone and dolomitic formation, each class was analyzed in separate table, see **Table 5 and Table 6** respectively. From **Figure 20 and Figure 22**, it can be observed that NMR is the best logging method to determine the porosity for clean limestone formations. This is indicated based on the below data from **Table 5** with an AARE of less than 10%, maximum relative error of less than 30%, error standard deviation of approximately 7% and correlation coefficient of 0.97 which displays better data match with the stressed core porosity.

On the other hand, high dolomitic percentage formations shows that NMR logging measurements is affected as shown in the **Figure 14** of highly scattered data with an AARE 85%, error standard deviation of approximately 120% , maximum error of 688% and correlation coefficient of 0.791 as shown in **Table 6**. The relaxation curve will decline much earlier than the normal limestone formations as it gets affected by the pores geometry. The T_2 spectrum will not be fully captured due to fast relaxation time decay for highly compacted dolomitic formation which cannot be captured by the tool.

Table 5: Results of porosity measurement techniques in clean limestone formation

Porosity Method	Minimum	Maximum	Mean	St.D	AARE	E_{MAX}	$E_{St.D}$	R
D-N	0.012	0.276	0.1915	0.08	14.3	67.6	12.6	0.944
Sonic	-0.043	0.25	0.1297	0.09	42.3	279	45.5	0.664
NMR	0.023	0.297	0.1824	0.07	9.74	29.3	7.26	0.966

Table 6: Results of porosity measurement techniques in dolomitic formation

Porosity Method	Minimum	Maximum	Mean	$S_{t.D}$	AARE	E_{MAX}	$E_{St.D}$	R
D-N	0.010	0.225	0.0431	0.05	40.2	252	42.3	0.857
Sonic	-0.046	0.197	0.0148	0.06	174	813	165	0.407
NMR	0.006	0.245	0.0653	0.06	84.4	688	117	0.791

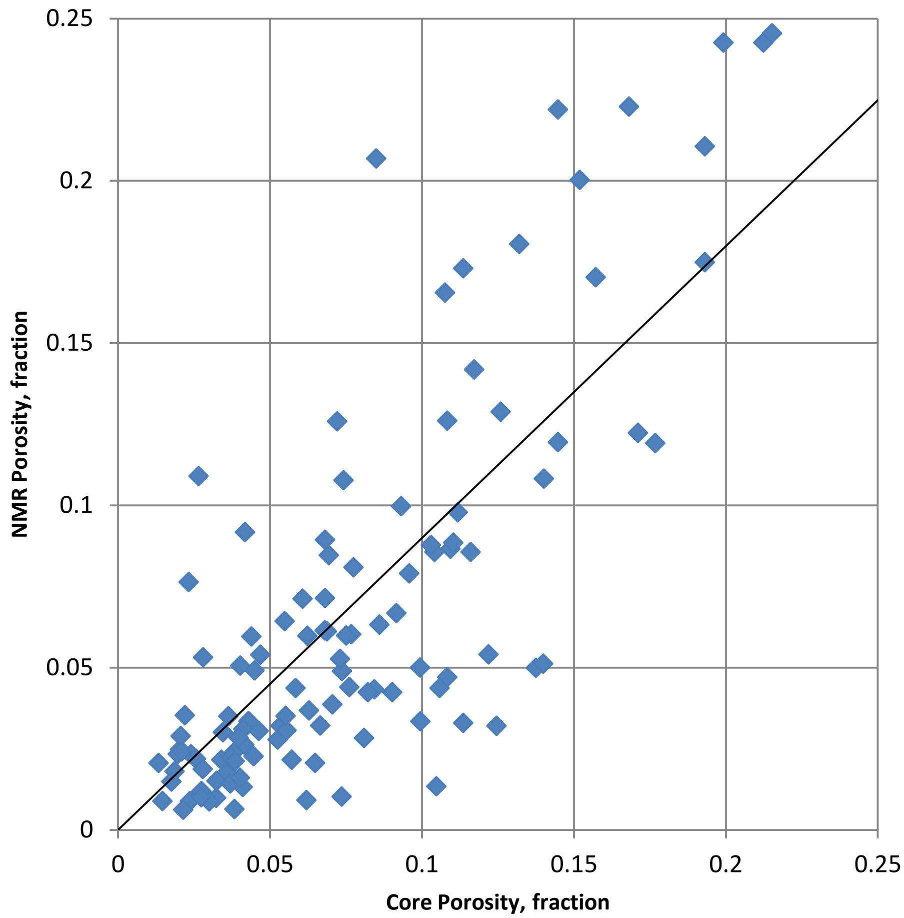

Figure 15: NMR logging porosity Vs. core porosity in the dolomitic sections

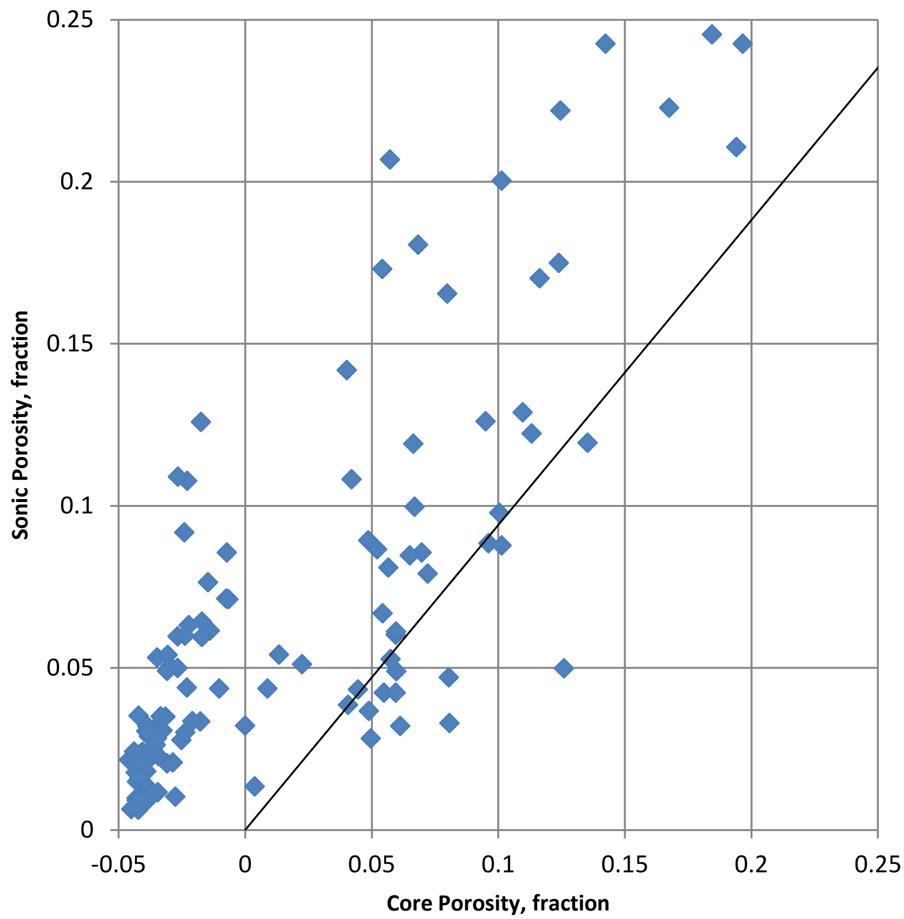

Figure 16: Sonic logging porosity Vs. core porosity in the dolomitic sections

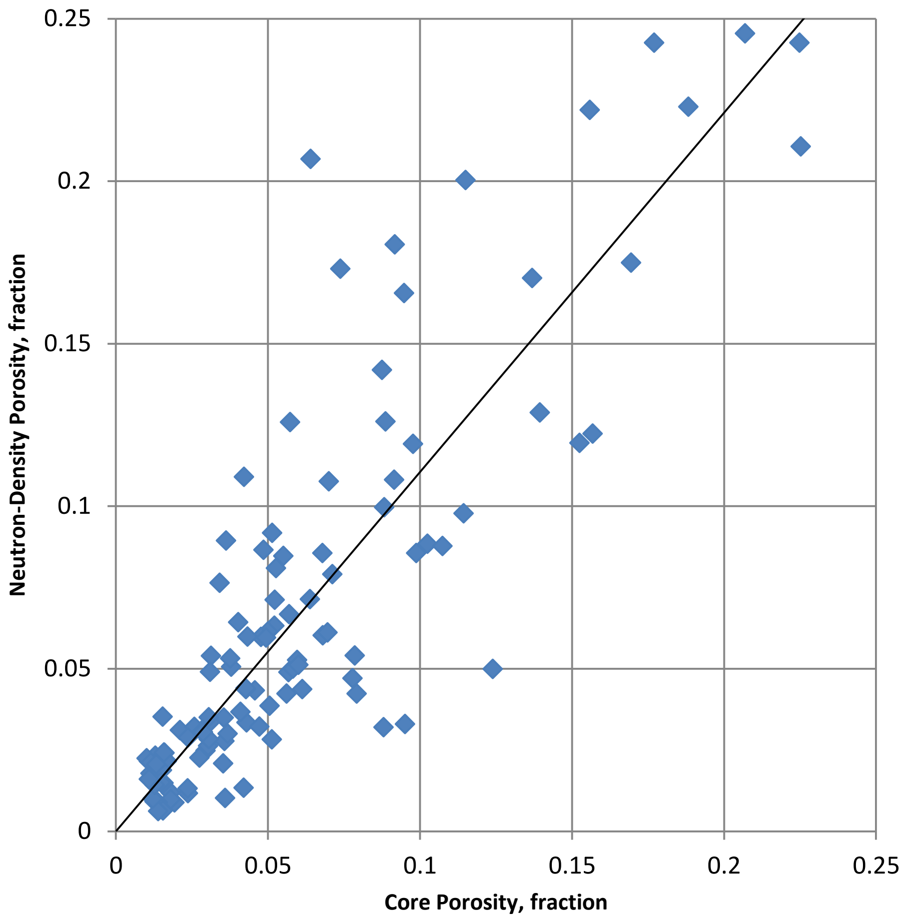

Figure 17: Neutron-Density logging porosity Vs. core porosity in the dolomitic sections

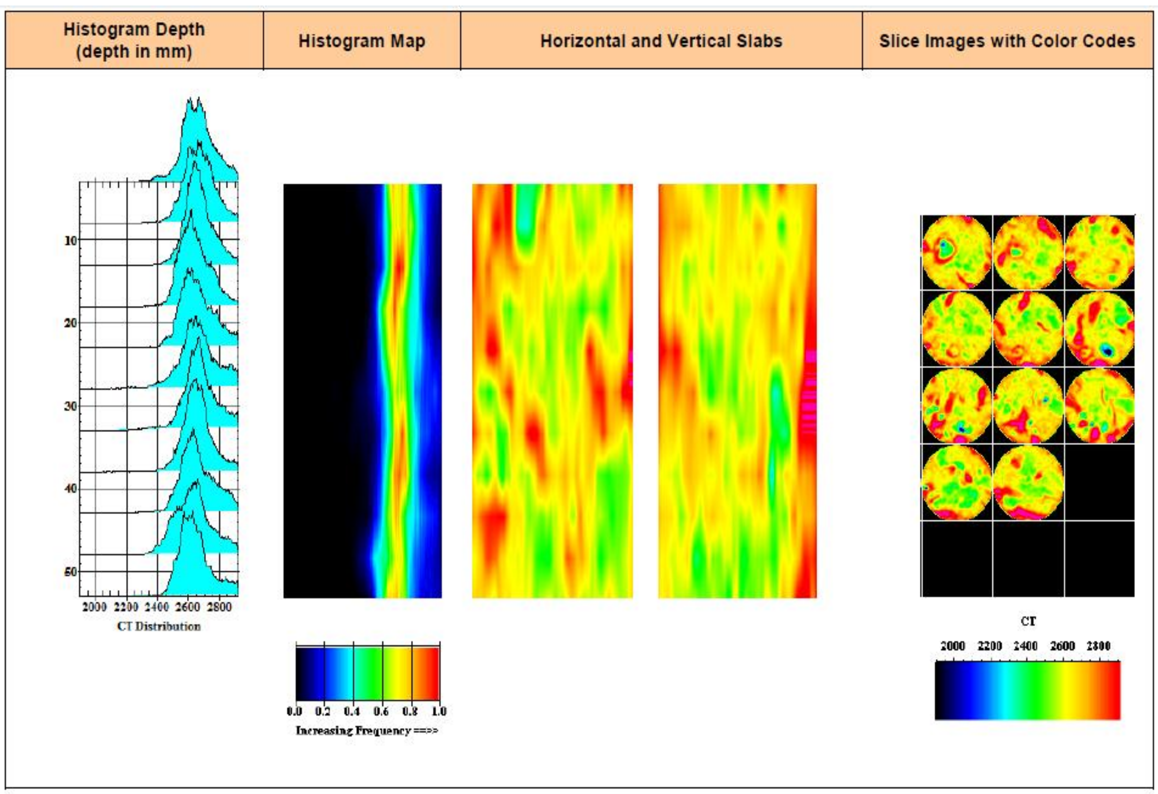

Figure 18: High density (dolomite) CT SCAN Images

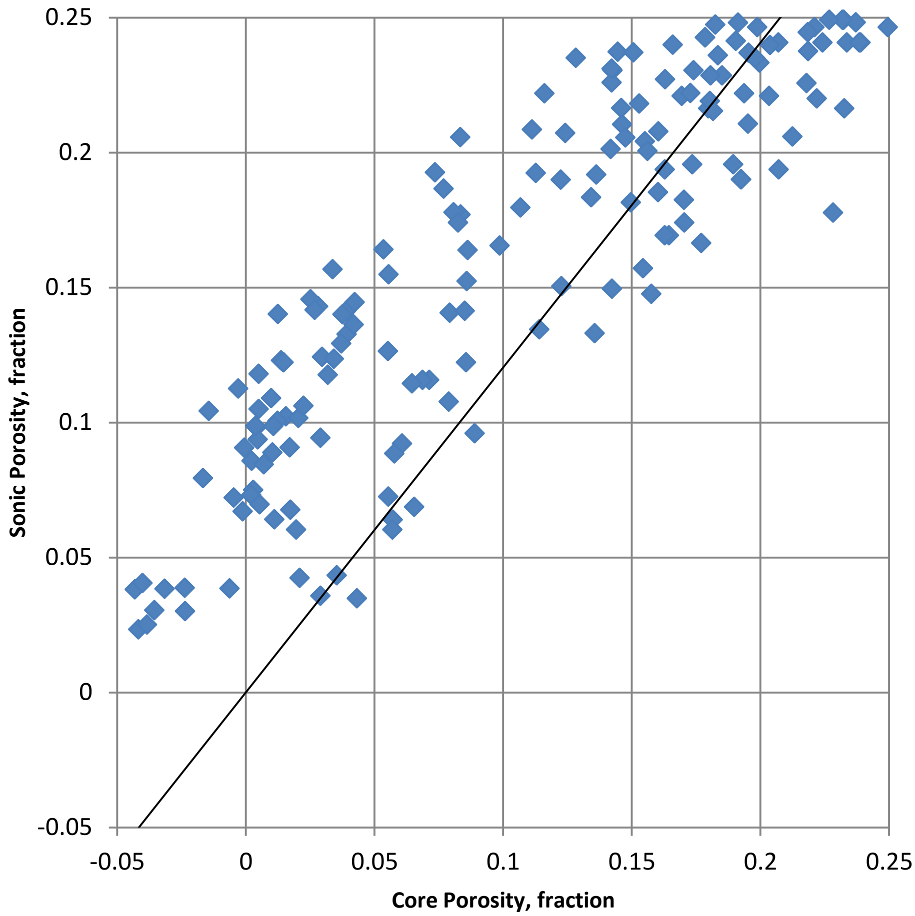

Figure 19: Sonic logging porosity Vs. core porosity in the clean limestone formation

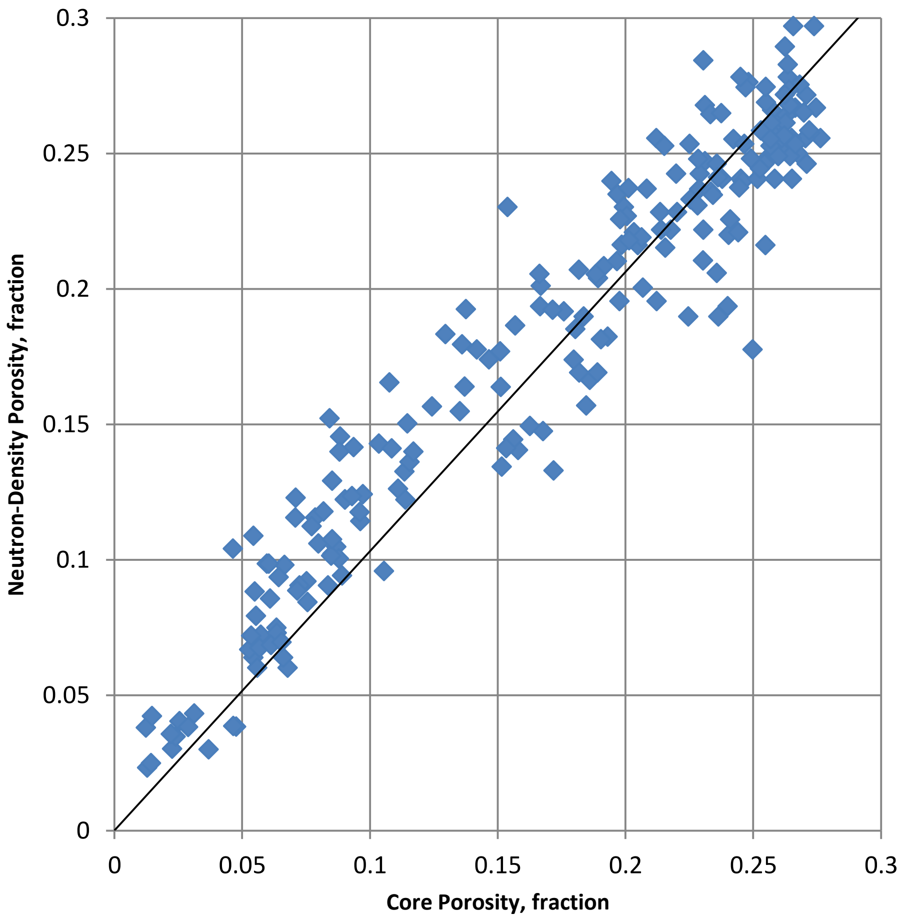

Figure 20: Neutron-Density logging porosity Vs. core porosity in clean limestone formation

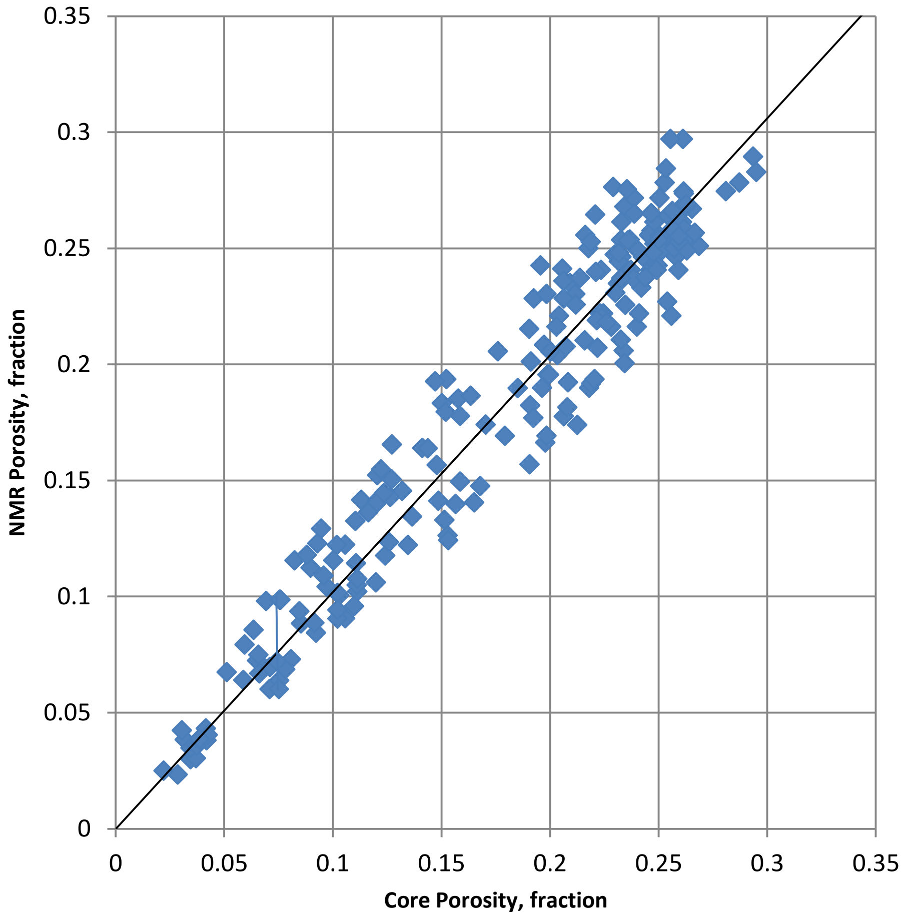

Figure 21: NMR Logging porosity Vs. core porosity in clean limestone formation

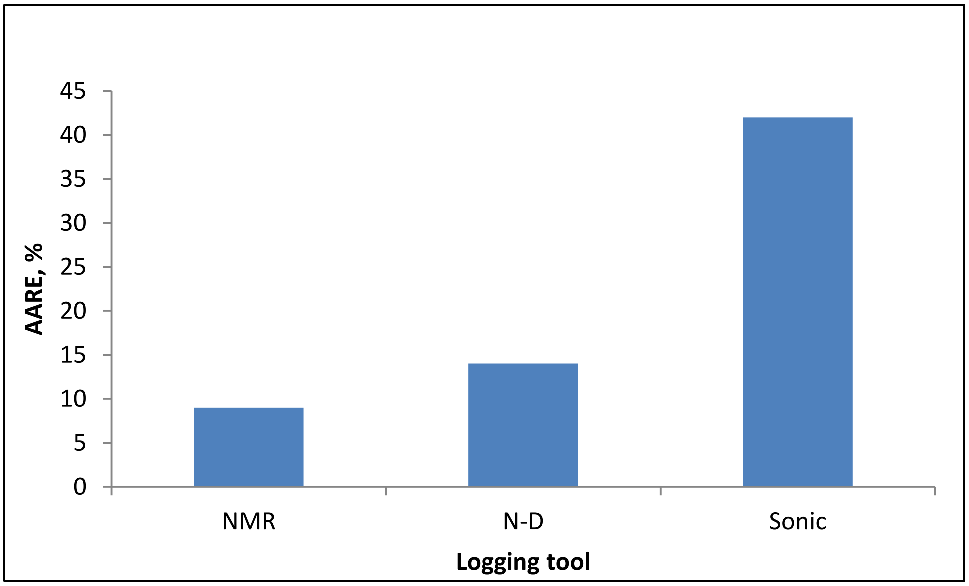

Figure 22: AARE for different tools in clean limestone formation

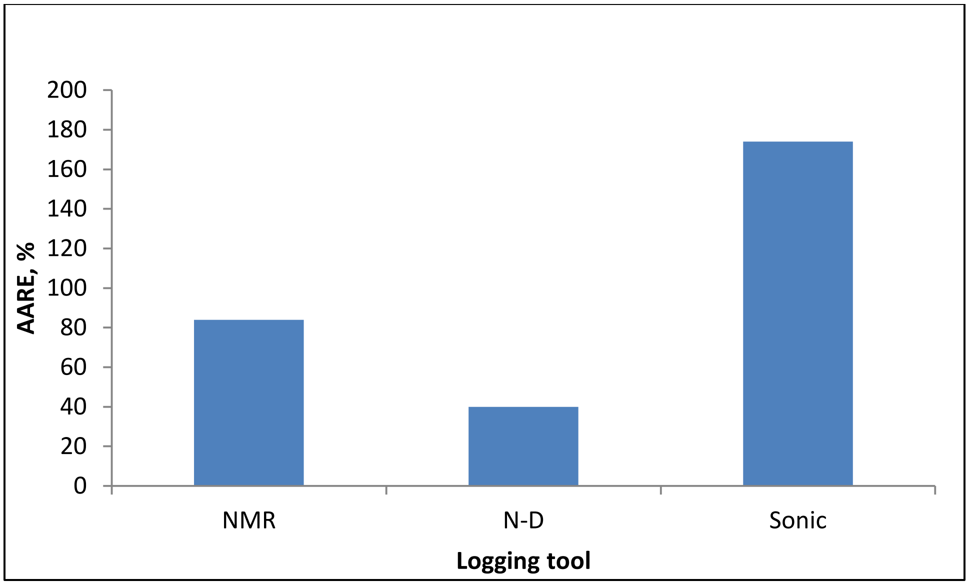

Figure 23: AARE for different tools in dolomitic formation

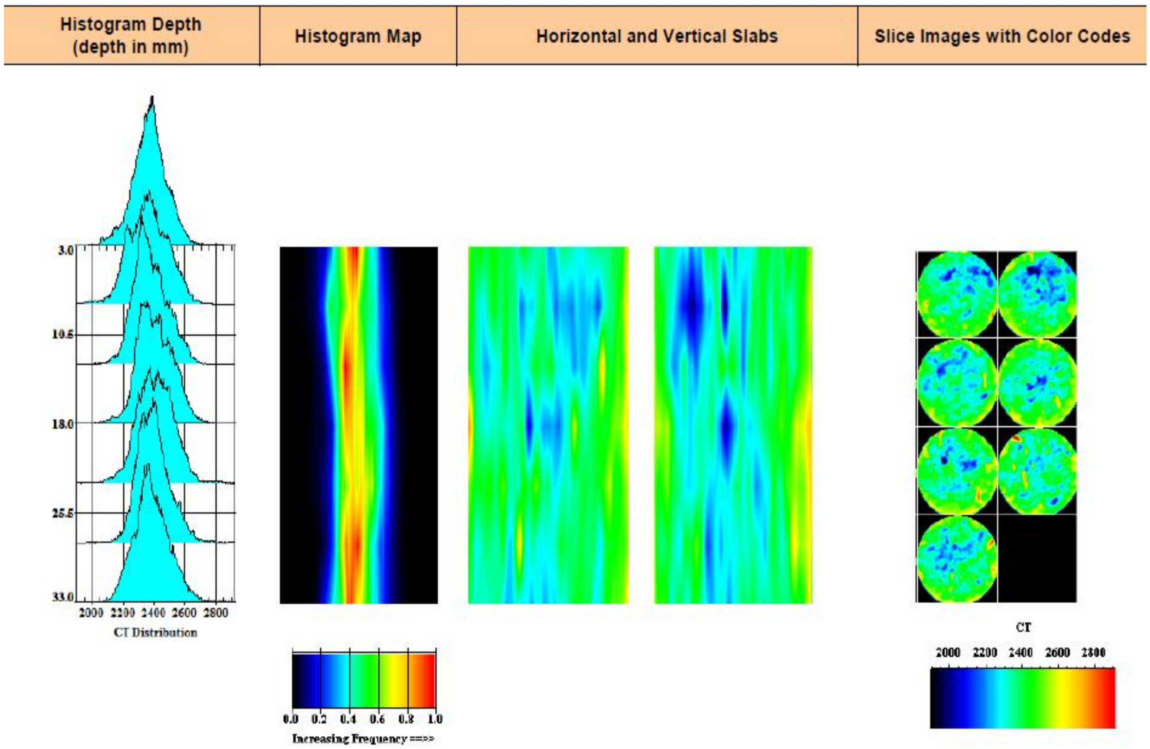

Figure 24: Low density CT SCAN Image

4.2 Comparison between Two NMR tools:

Two NMR tools where run in a carbonate well that has some washout sections. Tool-A is a pad tool and Tool-B is a centered. Two observations were found in this well washout sections affect the reading of Tool-A since it is pad tool and the depth of investigation for that tool is shallow. On the other hand, Tool-B shows better trend with core especially in washout section due to higher depth of investigation for that tool.

As shown in **Table 7**, both tools showed good agreements between NMR porosity and core porosity correlation coefficient (R) of almost equal to 1.0. While Tool-B is better with less scattered data of 60% $E_{St.D}$ compared to 104% $E_{St.D}$ for tool-A. Also Tool-B gives lower AARE (38%) than that for Tool-A (50%). Also, cross plot of the Tool-B porosity against core porosity shows better agreement than Tool-A porosity since it biased to one section of the borehole, while Tool-B has higher radius of investigation.

Table 7: Comparison between logging tools A and B in carbonate formation

Porosity Method	Minimum	Maximum	Mean	St.D	AARE	E_{MAX}	$E_{St.D}$	R
Core	0.0061	0.2649	0.0986	-	-	-	-	-
Tool-A	0.0134	0.2540	0.0979	0.0668	50	688	104.7	0.928
Tool-B	0.0137	0.2666	0.0954	0.0672	38	354	60.7	0.959

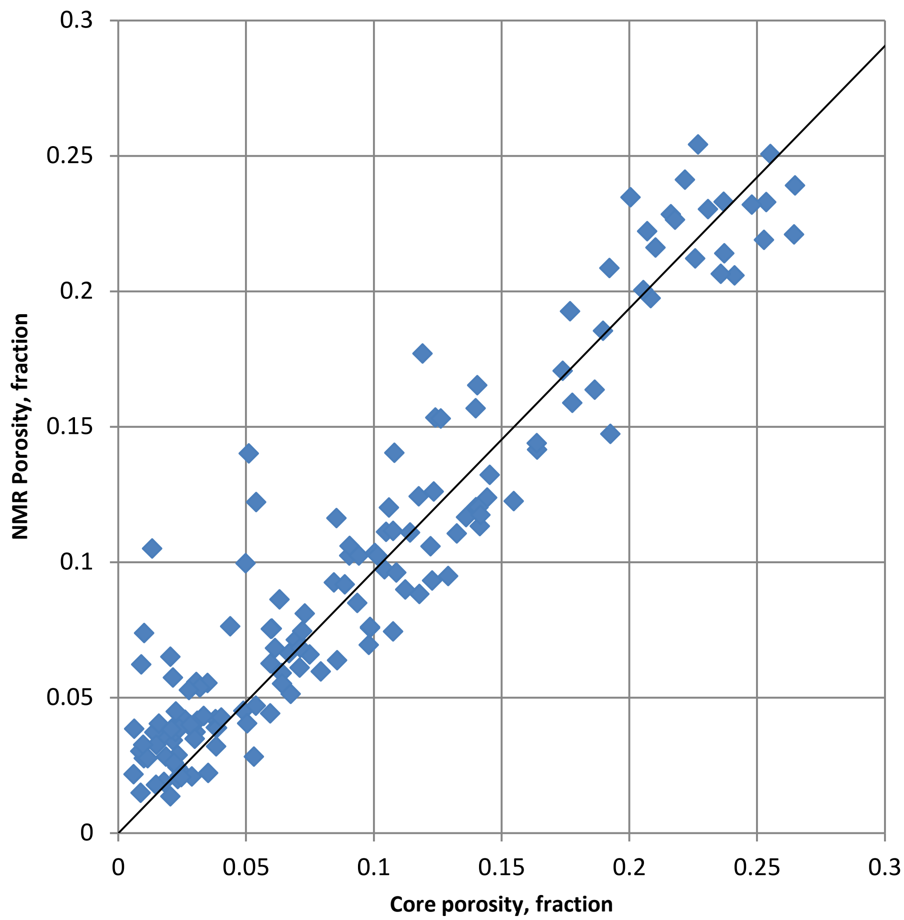

Figure 25: NMR logging porosity Vs. core porosity for tool-A

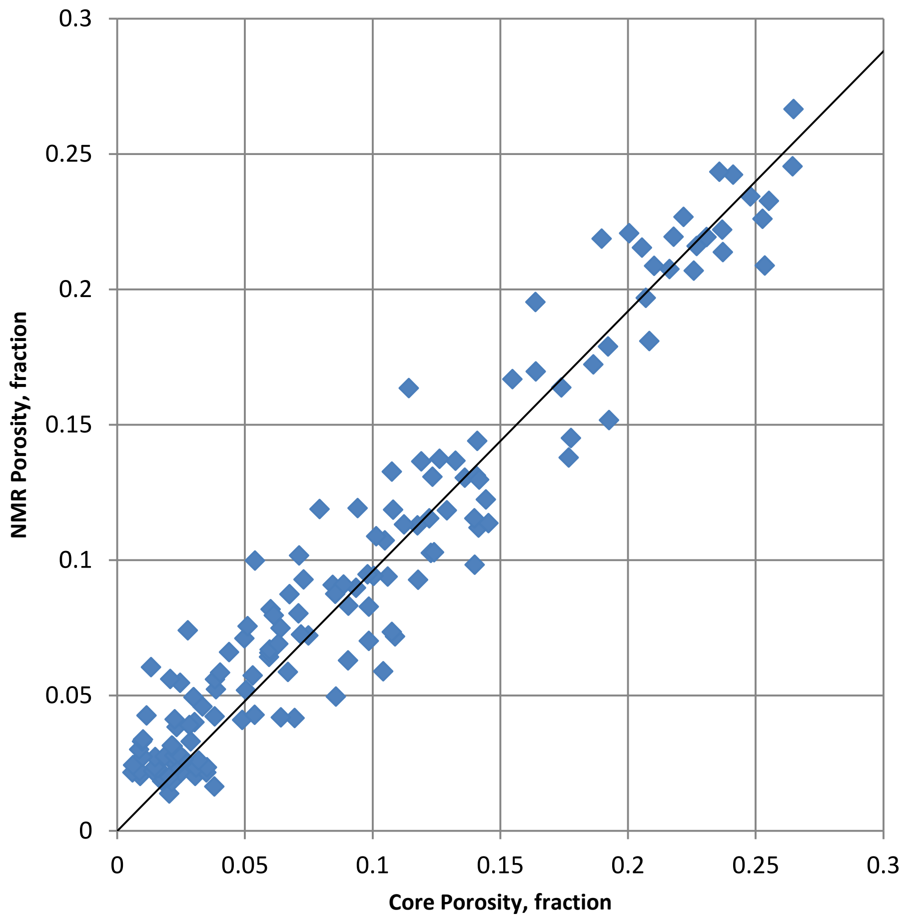

Figure 26: NMR logging porosity Vs. core porosity for tool-B

4.3 Porosity Correlation Determination:

Total porosity is the sum of movable fluid (FFI) and Bound Fluid (BFV) as shown by the following equation:

$$\text{Total Porosity: } \phi_T = \mathrm{FFI} + \mathrm{BFV} \tag{5}$$

Theoretically, the BFV can be estimated by integrating the area under the curve of T_2 spectrum from zero to BFV cutoff as illustrated in the following equation:

$$\text{Bound Fluid Volume: } \mathrm{BFV} = \int_0^{\mathrm{BFV\ Cutoff}} P(T_2)\, dT_2 \tag{6}$$

By subtracting BFV from the total area of T_2 spectrum (ϕ_T), free fluid will be estimated as shown below:

$$\text{Free Fluid: } \mathrm{FFI} = \phi_T - \mathrm{BFV} \tag{7}$$

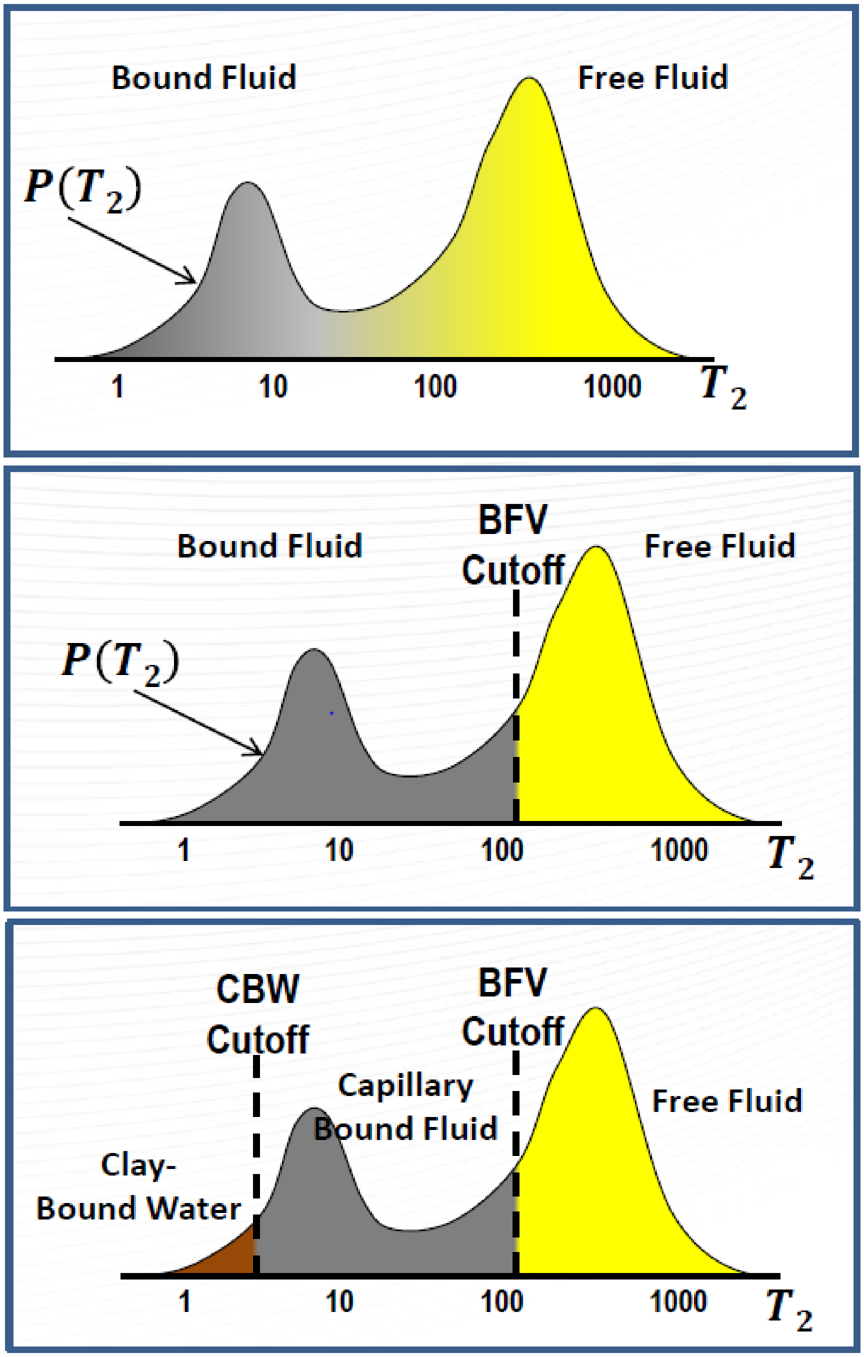

Figure 27: Movable and non-movable fluid

For clean limestone formations NMR logging data was used to develop correlations for FFI and BFV prediction.

$$CBW = 0.9865\,\phi_{NMR\ Log} - 0.0043 \tag{8}$$

$$FFI = 1.0232\,\phi_{NMR\ Log} - 0.0418 \tag{9}$$

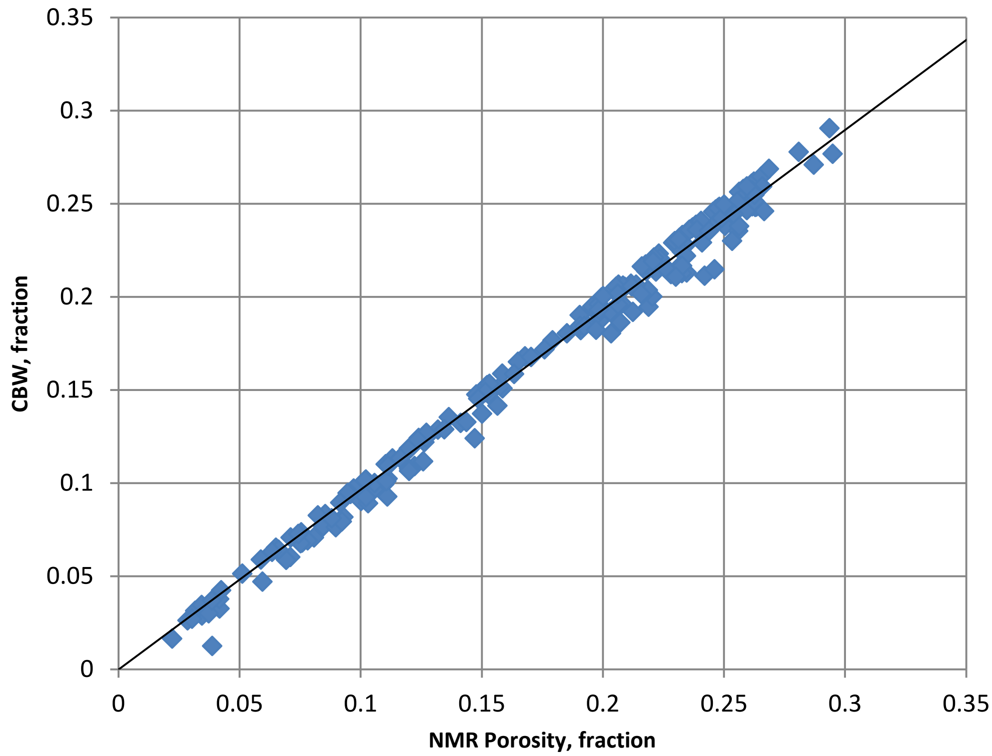

Figure 28: CBW Vs. NMR porosity in clean limestone formation

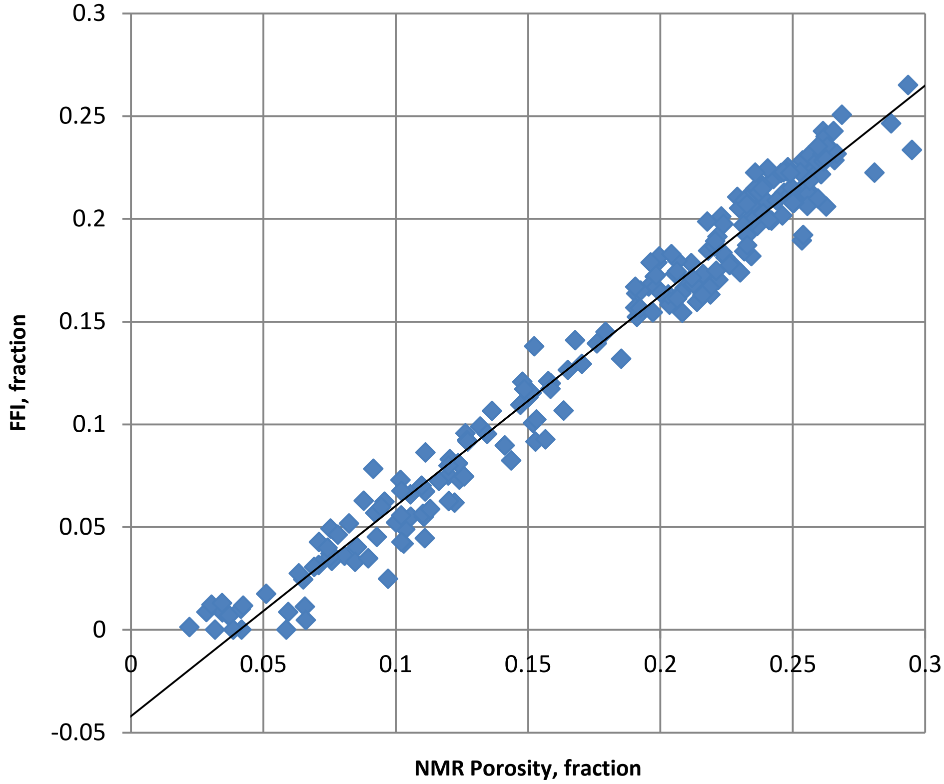

Figure 29: FFI Vs. NMR porosity in clean limestone formation

Both correlations estimate the FFI and clay bound water (CBW) porosities from the measured values of NMR porosity for Arab-D reservoirs. This can be used as a checking parameter for the used cutoff values by the service company to ensure full compliance with the measured values in the laboratory. In addition, these correlations will help in determining important parameters such as FFI and CBW for reserve estimation that are used to history match both static and dynamic simulation models. As shown in **Figures 25** and **26**, excellent linear match between the NMR values and both FFI and CBW values.

For dolomitic sections, since the pores are small, knowing CBW cutoff or T_{3MSEC} is very important for the porosity estimation. Therefore, data for dolomitic section was used again to develop similar correlation for Arab-D reservoirs (dolomitic sections) to estimate movable and non- movable fluid as shown in **Figures 27 and 28**.

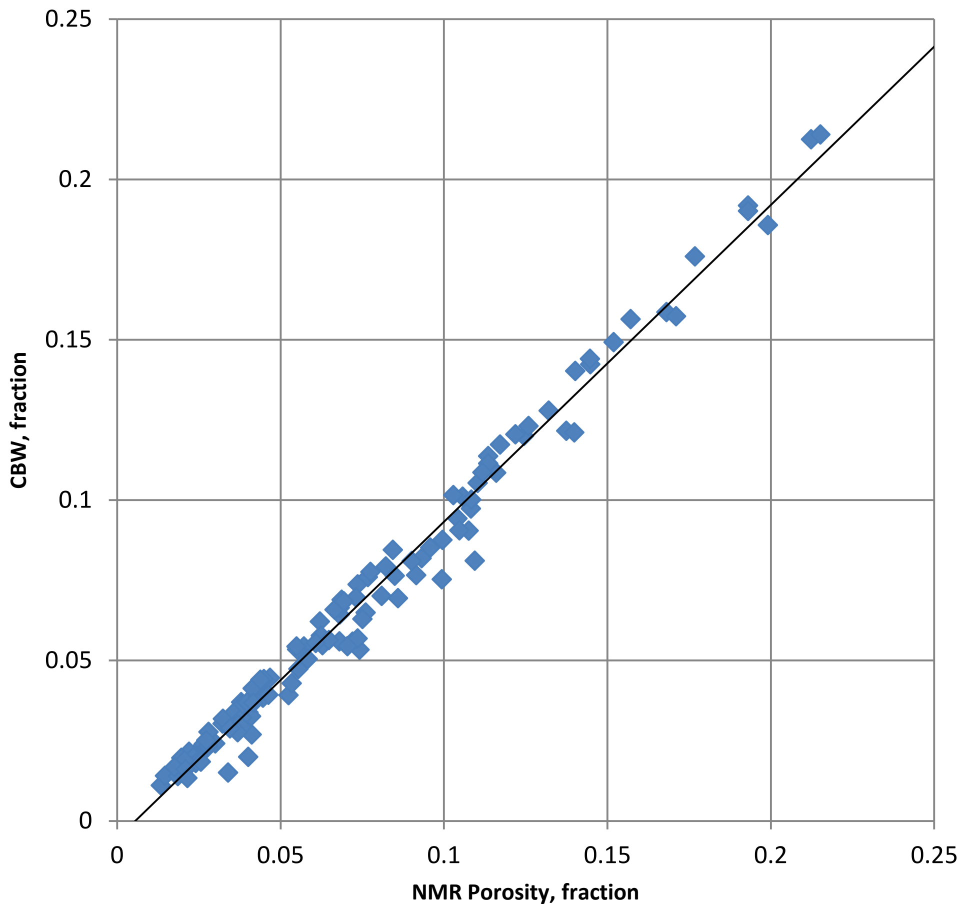

Figure 30: CBW Vs. NMR porosity in dolomitic section

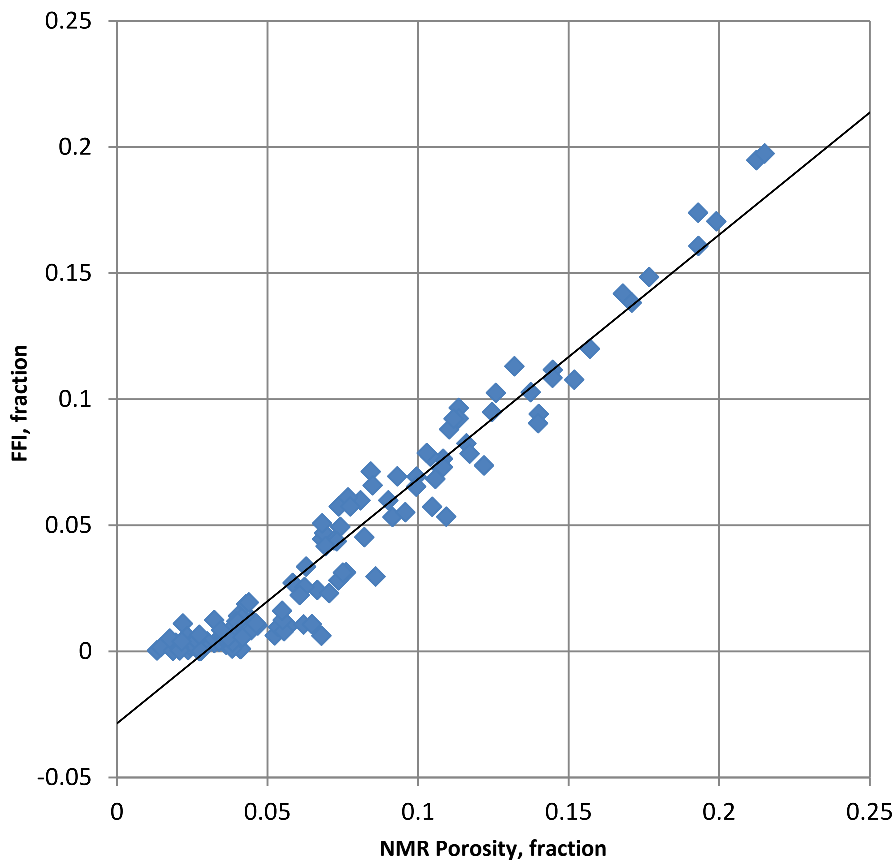

Figure 31: FFI Vs. NMR porosity in dolomitic section

These correlations are as follows:

$$CBW = 0.9878\,\phi_{NMR\ Log} - 0.0054 \qquad (10)$$

$$FFI = 0.9691\,\phi_{NMR\ Log} - 0.0285 \qquad (11)$$

NMR porosity strongly depends on pore size distribution, hence, in the dolomitic sections it shows inaccurate measurements compared to the core porosity. To over come this problem, JMP statistcal backage was used to devolped an emprical correlation that relates volume of dolmite, FFI and NMR porosity to give better estimation for NMR porosity in dolomaitic formation. This correlation was validated using 76 core samples from carbonate reservoir. The correlation is valid when the dolomite is 50% of or less by volume. On the other hand, there is a need to adjust the tool itself for dolomite effect like adjusting the T_2 cutoff for section containing 50% of dolomite or more.

$$\phi_{NMR\ corrected} = V_{dolomite} * FFI + (1 - V_{dolomite}) * \phi_{NMR\ Log} \qquad (12)$$

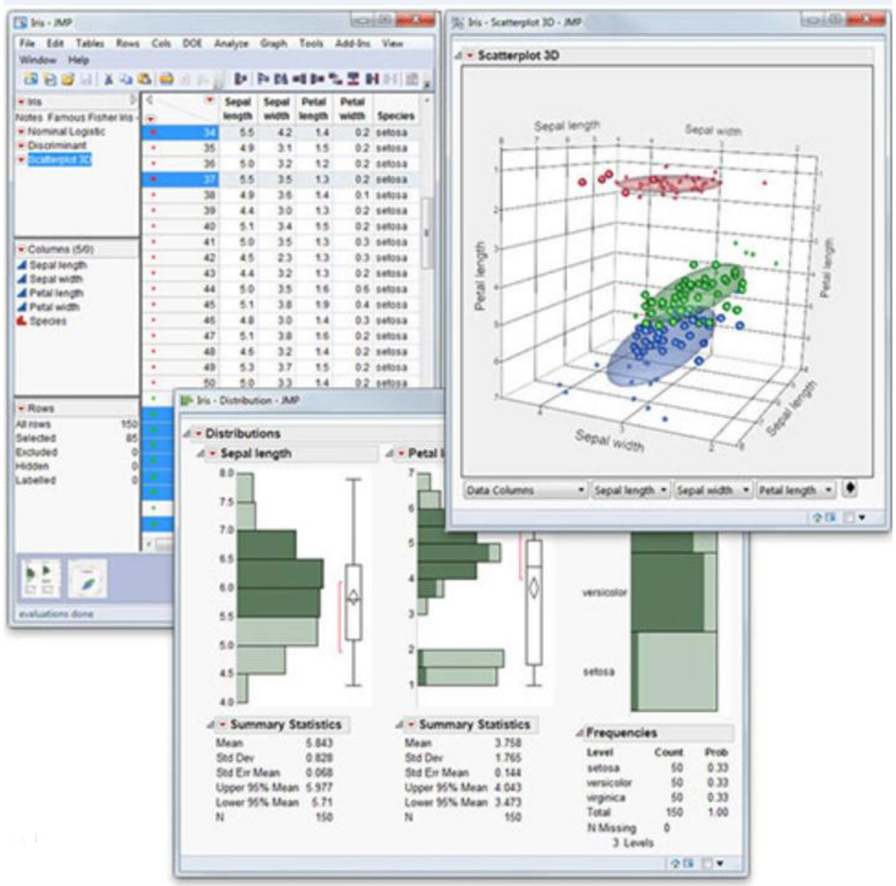

Figure ٣٢ : JMP statistical package

Table 8: Data description for porosity correlations

Porosity Method	Minimum	Maximum	Mean
Core	0.0061	0.2453	0.065
NMR logging	0.0134	0.2152	0.075
NMR correlation	0.008	0.208	0.067

Table 9: Results of porosity correlation

Porosity Method	$S_{t.D}$	AARE	E_{MAX}	$E_{St.D}$	R
NMR logging	0.047	84.40	688.10	117.01	0.79
NMR correlation	0.055	26.57	78.93	18.77	0.93

The correaltion shows an improvement of NMR porosity compared to the normal reading of NMR logging tool in the dolomitic sections, since it includes the effect of the small porethroat. **Table 8 and Table 9** summrizes the statistical comparsion between core porosity, NMR logging porosity and NMR corrected porosity. The mean values of the proposed correlation and core porosities match better than the mean values of the NMR logging poroity with an AARE of approximatly 27% and 84%, respectively as shown in **Figure 34**. Also, NMR correlation from **Figure 35** shows less scattering (R=0.93) comparing to the data set of NMR logging (R=0.79).

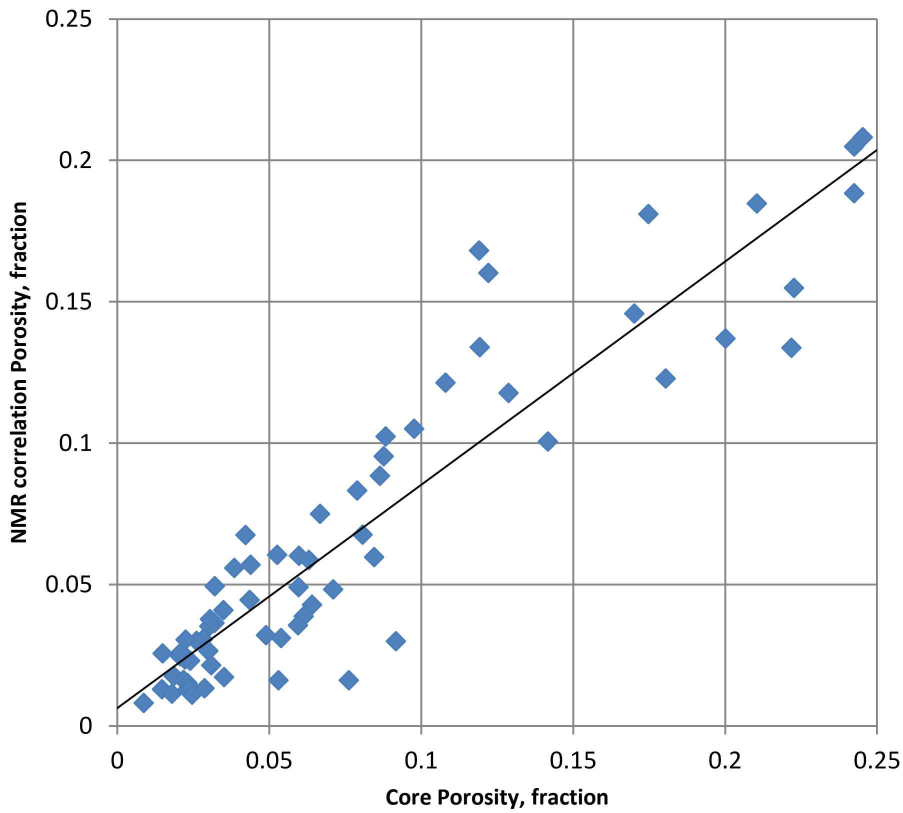

Figure 33: NMR correlation vs. core porosity in the dolomitic section

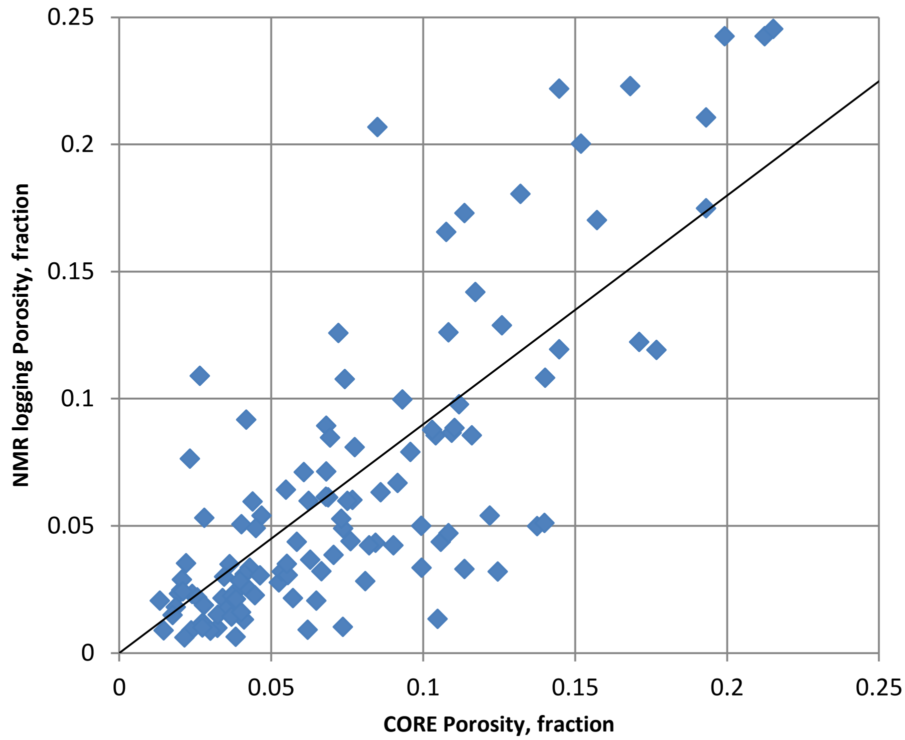

Figure 34: NMR logging Vs. core porosity in the dolomitic section

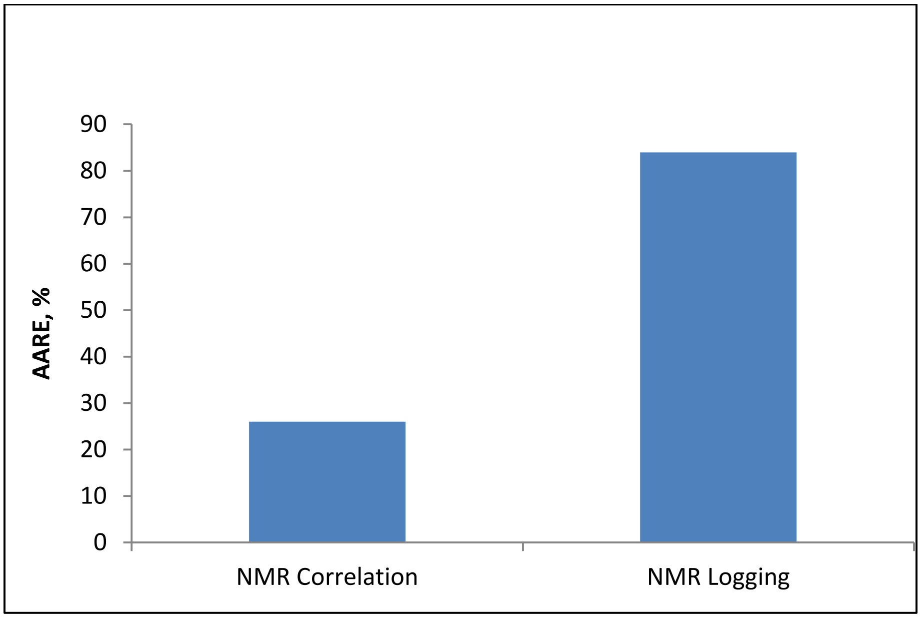

Figure 35: AARE for NMR vs NMR corrected in dolomitic formation

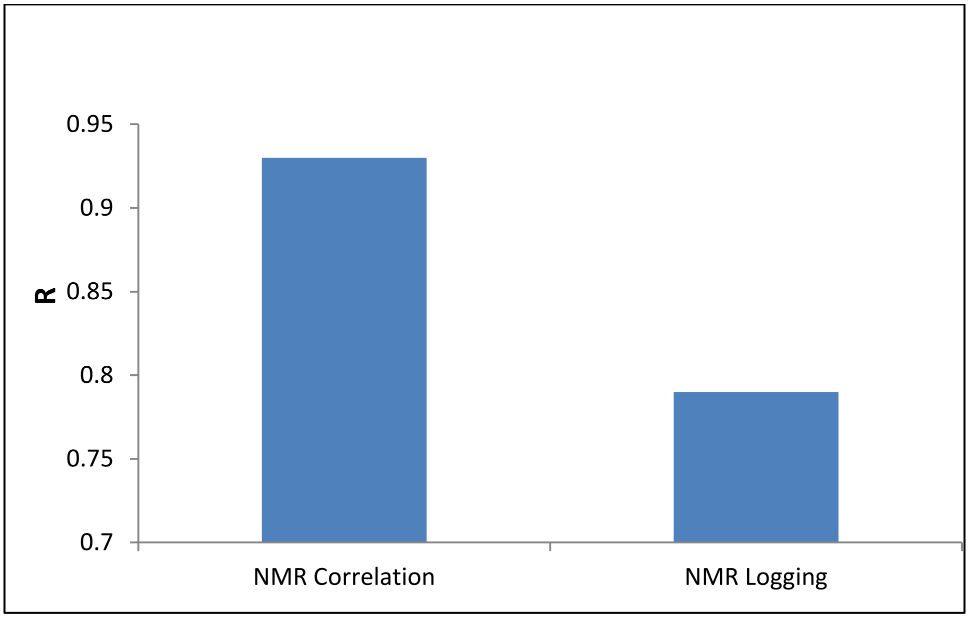

Figure 36: R for NMR vs NMR corrected in dolomitic formation

Conclusion:

For accurate estimation of hydrocarbon reserves, porosity determination is an important factor to be taken into account accurate reserve. In this comprehensive study total porosity was determined using different methods, namely, core laboratory, Computerized Tomography (CT) scan, neutron-density logging, sonic tools and Nuclear Magnetic Resonance NMR logging tools. An advantage of NMR logging is the independence on reservoir lithology which results in unique porosity values for most formations .However, it was found in this study that there is some deviation for formations with small pore throats. For carbonate formations, it is more complicated than sandstone to estimate total porosity due to its heterogeneity and triple porosity system (pores, vugs, and fractures). In addition, the assessment of porosity measurements accuracy using NMR logging was considered. Results of this study showed that a clear criterion to divide the formations into dolomitic and clean limestone formation (pure limestone) should be established to get more accurate result. In the dolomitic formation, Neutron-Density showed the least AARE of 40.2% compared to 84% for the NMR tool and 174% for the sonic tool. However, for clean limestone formation NMR tool was the most accurate tool with AARE of 10% compared to 14.3% for N-D tool and 42.3% for sonic tool. An empirical correlation was developed from NMR data to obtain reliable porosity prediction.

This correlation was generated to correct for porosity readings in dolomitic formations. NMR correlation shows less scattering (R=0.93) while the NMR logging tool gave (R=0.79) . Also, NMR logging correlation showed lower AARE of 27% than 84% for the NMR logging tool readings.

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APPENDIX

All mathematical formulas of error measures used in this study are given below including maximum absolute percent relative error (E_{MAX}), Average absolute percent relative error (AARE), Correlation Coefficient (R) and Standard Deviation ($E_{St.D}$).

$$E_{MAX} = \max\left(\left|\frac{\phi_a - \phi_m}{\phi_a} * 100\right|\right) \qquad \text{(Eq. 1)}$$

Where (ϕ_a) is core porosity and (ϕ_m) is measured porosity

$$\text{AARE} = \frac{1}{n}\sum_{i=1}^{n}\left|\frac{(\phi_a)_i - (\phi_m)_i}{(\phi_a)_i} * 100\right| \qquad \text{(Eq. 2)}$$

$$R = \frac{\sum_{i=1}^{n}\left((\phi_a)_i - \overline{\phi_a}\right)\left((\phi_m)_i - \overline{\phi_m}\right)}{\sqrt{\sum_{i=1}^{n}\left((\phi_a)_i - \overline{\phi_a}\right)^2 \sum_{i=1}^{n}\left((\phi_m)_i - \overline{\phi_m}\right)^2}} \qquad \text{(Eq. 3)}$$

Where $\overline{\phi_a} = \frac{1}{n}\sum_{i=1}^{n}(\phi_a)_i$ and $\overline{\phi_m} = \frac{1}{n}\sum_{i=1}^{n}(\phi_m)_i$

$$E_{St.D} = \left(\frac{1}{n-1}\sum_{i=1}^{n}(Ei - \bar{E})\right)^2 \qquad \text{(Eq. 4)}$$

Where Ei= $(\phi_a)_i - (\phi_m)_i$ and $\overline{E} = \frac{1}{n}\sum_{i=1}^{n} E_i$

Vitae

Name	: HAMAD SALMAN ALKHARRAA
Nationality	: Saudi
Date of Birth	:3/26/1987
Email	: KHARAAHS@ARAMCO.com
Present Address	: Dammam
Permanente Address	: Dhahran
Academic Background	: Petroleum Engineering
Telephone Number	: +966533332959