Magnetic Resonance Imaging Log

Productivity Analysis
IMMOKALEE IW #1

BAKER HUGHES

Baker Atlas

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INTRODUCTION:

The analogous behaviors of capillary pressure and $1/T_2$ decay versus saturation data provide a methodology for deriving synthetic capillary pressure information directly from NMR logs even if core data are not available. Estimations of irreducible water saturation from NMR log-based synthetic capillary pressure profiles have numerous benefits. One benefit is the enhanced accuracy of permeability estimations by using synthetic bulk volume irreducible in the bound water model. Availability of synthetic bulk volume irreducible data from capillary pressure modeling eliminates the requirements for determining the T_2cutoff time from core analysis data or assuming generally accepted constants for it (33 ms for clastics and 92 ms for carbonates). In addition to the bound water model, an alternative permeability profile can also be generated from Purcell's capillary pressure-permeability relation.

Relative permeability estimations from synthetically created capillary pressure data provide an avenue to make the first-approximation profiles of the effective permeability values to the phases contained in the pore space. Consequently, effective permeability profiles in conjunction with other petrophysical and fluid properties and the pressure information lead to the anticipated production rates and overall evaluation of the economic viability of a well(s) and field.

THEORETICAL BACKGROUND:

The governing equation for the T_2 decay phenomena for spin-spin relaxation can be written as follows:

$$\frac{1}{T_2} = \underbrace{\frac{1}{T_{2_{bulk}}}}_{\substack{\text{Bulk} \\ \text{Relaxation}}} + \underbrace{\rho\frac{S}{V}}_{\substack{\text{Surface} \\ \text{Relaxation}}} + \underbrace{\frac{1}{12}\gamma G^2\, \text{TE}^2 D}_{\substack{\text{Relaxation due} \\ \text{to diffusion}}}$$

Historically, to obtain capillary pressure from NMR data started from the observance of the similarity between the inverted magnetization decay of the polarized pore-filling fluids and the pore-size distribution obtained from capillary pressure data for the same sample. NMR T_2 decay in porous media is commonly simplified and interpreted in terms of pore size distribution (where pore size distribution is used synonymously with pore-body size). In its simplified form, the T_2 relaxation time is proportional to the ratio of the pore volume to pore surface area and is inversely proportional to surface relaxivity. It should be noted that this relationship is valid when pores are water wet, there is no diffusive coupling, the T_2 distribution is not shifted by the presence of hydrocarbons and the T_2 of the bulk fluid is large enough to drop the term $(1/T_{2bulk})$ from the preceding equation.

Construction of capillary pressure curves from NMR data is based on fundamental definitions of capillary pressure and the T_2-decay phenomena; hence the complexities caused by the presence of hydrocarbons and their respective placement in various size pores must be addressed after the introduction of the linkage between these two. When porous media contain more than a single fluid, the pressure for each fluid differs even if the fluids are in a state of pressure equilibrium. The mutual attraction between porous media and fluid (adhesion tension) differ for each couple, which is the reason for the pressure imbalance, defined as capillary pressure. This concept can be expressed in terms of the following equation:

$$P_c = \frac{2\,\sigma\cos(\theta)}{r_{pt}}$$

Capillary pressure may be determined from laboratory tests, or correlation, or calculated from known fluid distributions and fluid properties. In this study, we will elaborate on the methodology to convert log NMR data into P_c versus saturation profile without the availability of core data.

In capillary phenomenon, the pressure imbalance between two phases is mostly controlled by pore throat size. On the contrary, S/V term in the T_2 decay equation yields the pore body size. To equate capillary pressure and T_2-decay equations would be troubling if not for the fact that commonly there is a relation between pore-body and pore-throat size, an occurrence or a fractal quality more common for clastics than carbonates. As pores deviate from geometrically definable shapes into irregular voids with stretched extensions, the relation between pore-body and pore-throat size deteriorates and becomes more difficult to quantify. Consequently, the ability to compute properties depending on pore-throat attributes from pore-body attributes becomes less reliable.

If we assume a geometrically definable shape for pores (spherical or tube like), however, we can write the surface to volume ratio in terms of pore size:

$$\frac{S}{V} = \frac{F_s}{r_b}$$

for a spherical pore:

$$\frac{S}{V} = \frac{4 \cdot \pi \cdot r^2}{\frac{4}{3} \cdot \pi \cdot r^3} = \frac{3}{r}$$

The shape factor (F_s) is 3 for round pores and 2 for cylindrical tubes. Both equations (P_c and T2-decay) define two different phenomena and can be linked by their common variable pore-throat-size (r_{pt}) for the capillary pressure and the pore-body-size from the T_2-decay with an assumption of correlatable body to throat size. If we substitute the r_{pt} in the capillary pressure equation with the corresponding T_2 term from the T_2-decay equation, capillary pressure can be expressed within the terms of T_2 decay phenomenon for spin-spin relaxation.

$$\frac{1}{P_c} = \frac{\rho}{2\sigma\cos(\theta)} \frac{r_{pt}}{r_b} F_s T_2$$

By rearranging the above equation and regrouping the surface relaxivity and pore throat to pore body ratio into a variable called C:

$$C = \frac{\rho}{2\sigma\cos(\theta)} \frac{r_{pt}}{r_b} F_s$$

We can simplify the original equation into:

$$\left(\frac{1}{P_c}\right) = C T_2$$

Algebraic manipulation of the above relation between the capillary pressure and the T_2-decay yields:

$$Log(C) = Log\left(\frac{1}{P_c}\right) - Log(T_2)$$

This is the coefficient that scales the S_w versus T_2 curve to match as close as possible to S_w versus $1/P_c$ curve. The coefficient serves as a merit function in the absence of hydrocarbons.

Any deviation between the $C*T_2$ and $1/P_c$ versus S_w curves (as observed in the very low S_w values) maybe because of the inapplicability of the selected shape factor or any variability in the surface relaxivity or possibly both.

In most cases, to identify the reasons for the deviation and to rectify the scaling coefficient is impossible due to lack of data or simply lack of rock samples. Of note is the scaling coefficient C does not reflect the effects of magnetic susceptibility on the magnetic field. Nevertheless, the C computed as a variable for each saturation level (at each time segment of the inversion) suffices for the reasonably accurate transformation of NMR data into capillary pressure information provided that the correction of T_2-spectra for non-wetting hydrocarbons is performed (Volokitin et al. SCA 9924). For the studied water well, there was no reason for this correction due to the lack of any hydrocarbons.

We used the above methodology to generate scaling coefficient tables for any subject formation by using a porosity-range- qualifier. The porosity-range-qualifier checks NMR log derived porosity to select the proper C table for that range of clastics or carbonates for processing the wireline NMR data to derive capillary pressure versus saturation profile for the given depth level or interval. The accuracy of this procedure becomes better when core calibration of the C coefficient is possible.

In the absence of core data, we devised a methodology to convert the NMR log data to capillary pressure based on the same concept for deriving the proper scaling coefficient. Derivation of the scaling coefficient from hydrocarbon-corrected T_2-spectra relies on the analogy between the time dependent desaturation of a core plug at a constant capillary pressure and the time dependency of the partial porosity buildup in an NMR experiment. First, the transformation of T_2 versus ϕ_i into T_2 versus S_w is obtained. Then, the rate of change in porosity build up is computed. The rate of change in cumulative partial porosity is reflective of the changing pore sizes and also analogous to desaturation rate at an increasing capillary pressure (increased rpm) in a centrifuge Pc test.
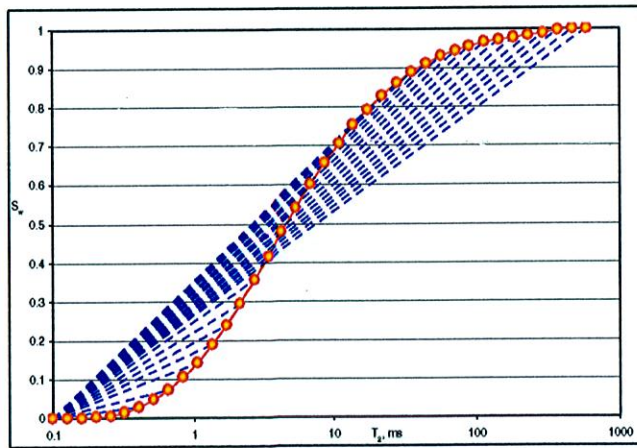
$$m_i = \frac{dS_{w_i}}{dT_{2_i}}$$

The slope change is computed from the initiation time of the NMR experiment to the end of each time increment. The ratio of effective pore volume to cumulative slope change for each increment yields a multiplier for each time slice. In the absence of core data for calibration of "C" –the merit function- or -the scaling coefficient-; the derived model equation based on historical core capillary pressure and NMR test data is used for generating the C. The model equation for C is derived for sandstone and carbonates covering a wide range of shape factors and porosity ranges. The transformation is completed with the plot of P_c versus S_w.

APPLICATION:

Reasonably accurate estimations of capillary pressure versus saturation profile for every level of wireline log data signals new avenues for using NMR logs in the domain of reservoir and production engineering in addition to petrophysical interpretations. We will elaborate on the immediate byproducts of the methodology.

1. Bulk volume irreducible (BVI) information independent of T_2cutoff or Spectral BVI coefficients.

NMR-derived capillary pressure curve is treated with a model equation to extrapolate the curve to very large capillary pressure levels to attain the theoretical S_{wir}. The same model also provides the threshold pressure as S_w approaches 100% by the parameter estimation technique provided that the hydrocarbon correction of the T_2 distribution is performed. The form of the model equation is as follows:

$$S_w = S_{wir} + (1 - S_{wir})\frac{P_d}{P_c} + (1 - S_{wir})\frac{P_d}{P_c}Ln(\frac{P_c}{P_d})$$

where:
S_w = wetting phase saturation
S_{wir} = Irreducible water saturation
P_d = Threshold (entry) pressure
P_c = Capillary pressure

The above equation satisfies the boundary conditions of the capillary pressure phenomenon: S_w approaches S_{wir} when P_c approaches infinity and P_c approaches a finite number (P_d) when S_w approaches 100 %. Theoretical irreducible at infinite capillary pressure helps to eliminate the ambiguity in permeability models that are based on BVI by equating the computed permeability to absolute permeability.

2. Capillary pressure profile

The capillary pressure profile for the entire coverage of the NMR log is created. Theoretical (absolute) S_{wir} is computed by using the preceding model equation. Pore throat size histograms for any given interval can also be computed provided the shape factor that links the pore body and pore throat size is not grossly in error and the hydrocarbon shift of the T_2-spectra is corrected.

3. Purcell's permeability model[7]

Purcell relates the permeability of a unit system of cylindrical capillaries with various radii to the porosity and the capillary pressures and volumes of its components by:

$$k = \frac{(\sigma \cdot \cos\theta)^2 \phi}{2 \cdot 10^4} \sum_{i=1}^{N} \frac{S_w}{P_c^2}$$

The above equation is for a theoretical porous media and does not consider the interconnectivity of the pore networks; hence Purcell introduced a lithology factor to account for the differences between theoretical and hypothetical porous media. The equation is then reduced to:

$$k = 0.66 \cdot F\phi \int_{Sw=0}^{Sw=100} \frac{dP}{P_c^2}$$

where k is the permeability in mD, ϕ is the porosity in percent, S_w is the wetting phase saturation in percent and P_c is the capillary pressure in atmosphere. A permeability range varying from 1 to 1450 mD has a lithology factor average of 0.216 with minimal variability.

4. Relative permeability by Corey-Burdine[12] equations

Relative permeability to wetting and non-wetting phases is computed by interrelating the synthetic capillary pressure with the Corey-Burdine equations. These equations have recently been re-worked by Huang et al[13]. for the drainage and imbibition cycles, and are presented below:

Wetting phase relative permeability:

$$k_{rw} = \left(S_w^*\right)^2 \cdot \frac{\int_0^{S_w^*} \frac{1}{P_c^2} dS_w^*}{\int_0^1 \frac{1}{P_c^2} dS_w^*}$$

For the non-wetting phase, the equation is as follows:

$$k_{rnw} = \left(1 - S_w^*\right)^2 \cdot \frac{\int_0^{S_w^*} \frac{1}{P_c^2} dS_w^*}{\int_0^1 \frac{1}{P_c^2} dS_w^*}$$

where:

S_w^* is normalized wetting phase saturation:

$$S_w^* = \frac{S_w - S_{iw}}{1 - S_{iw} - S_{or}}$$

5. Relative permeability by regression models

Empirical relative permeability models compiled and derived[9,10,11] from the historical SPE database classified by system, lithology, and wettability are used in conjunction with the resistivity-based or DTW-based S_w analysis to derive relative permeability characteristics of the porous media.

6. Fractional flow of water

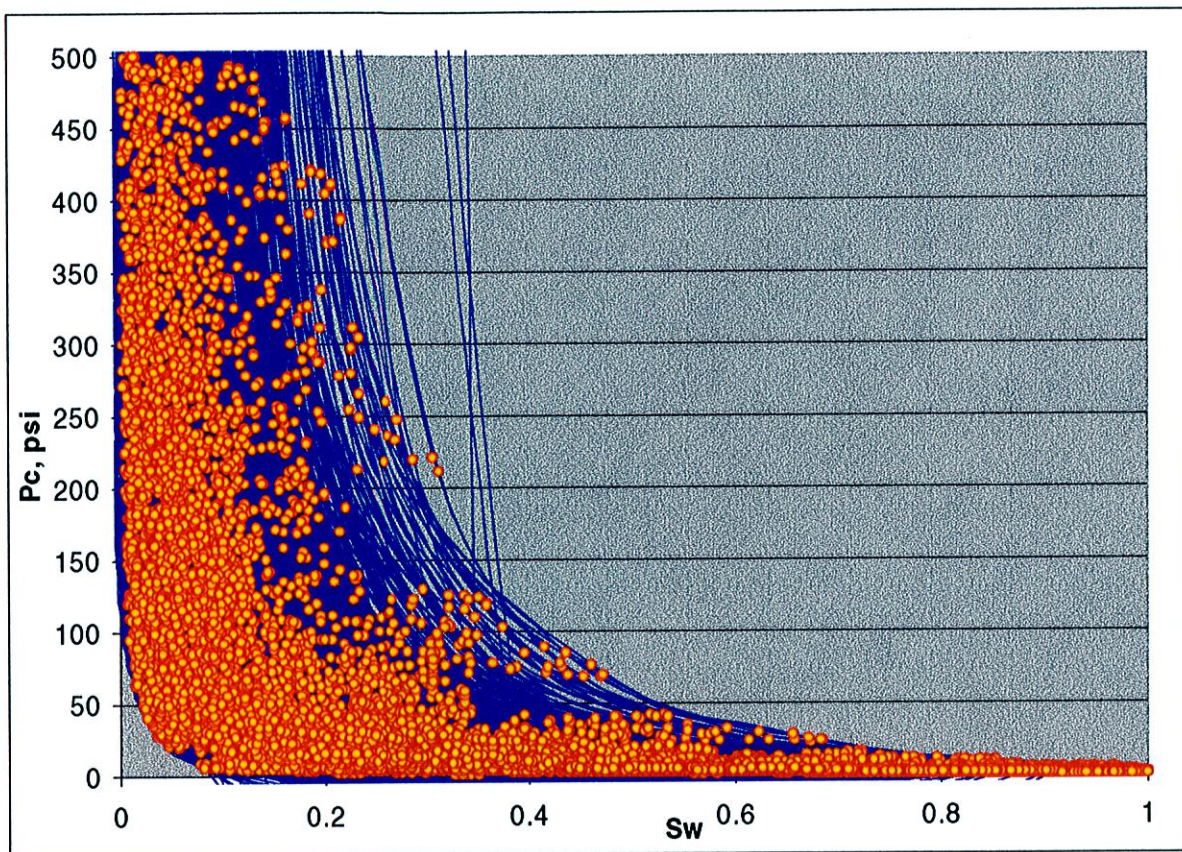Fractional flow of water[16] can be computed for each level by using:

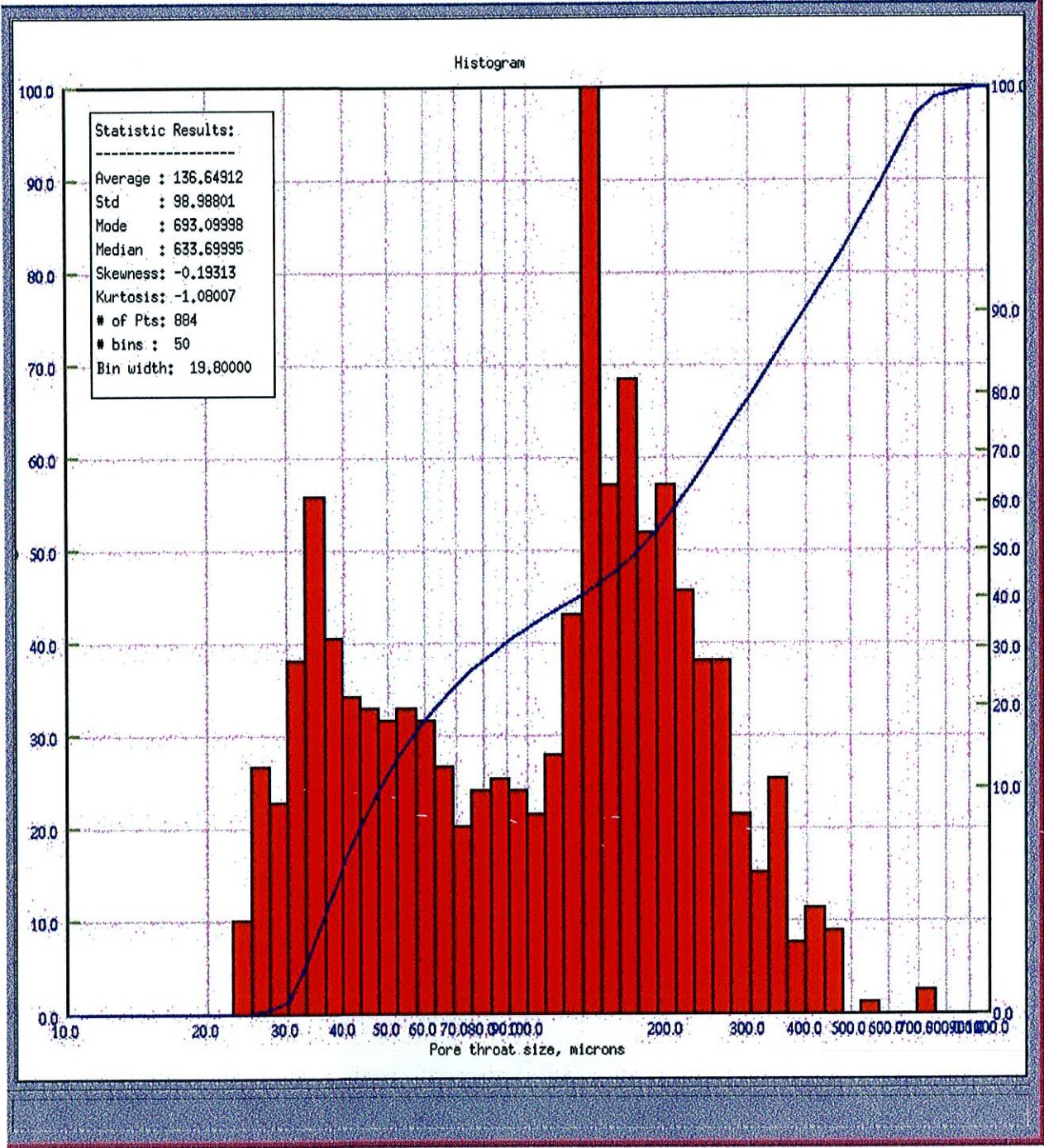$$fw = \frac{1}{1 + \frac{k_{rnw}}{k_{rw}} \cdot \frac{\mu_w}{\mu_{nw}}}$$

and plotted (f_w versus S_w) for any given interval or for the entire profile.
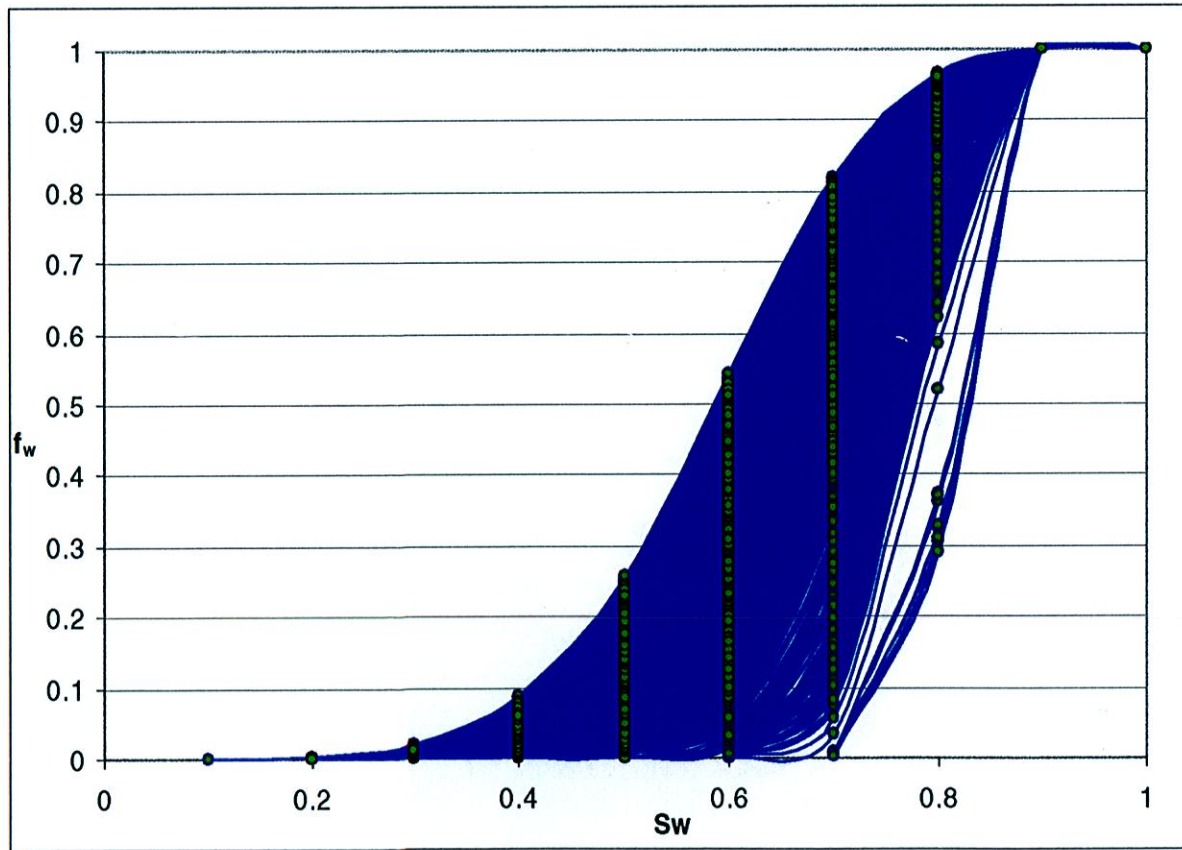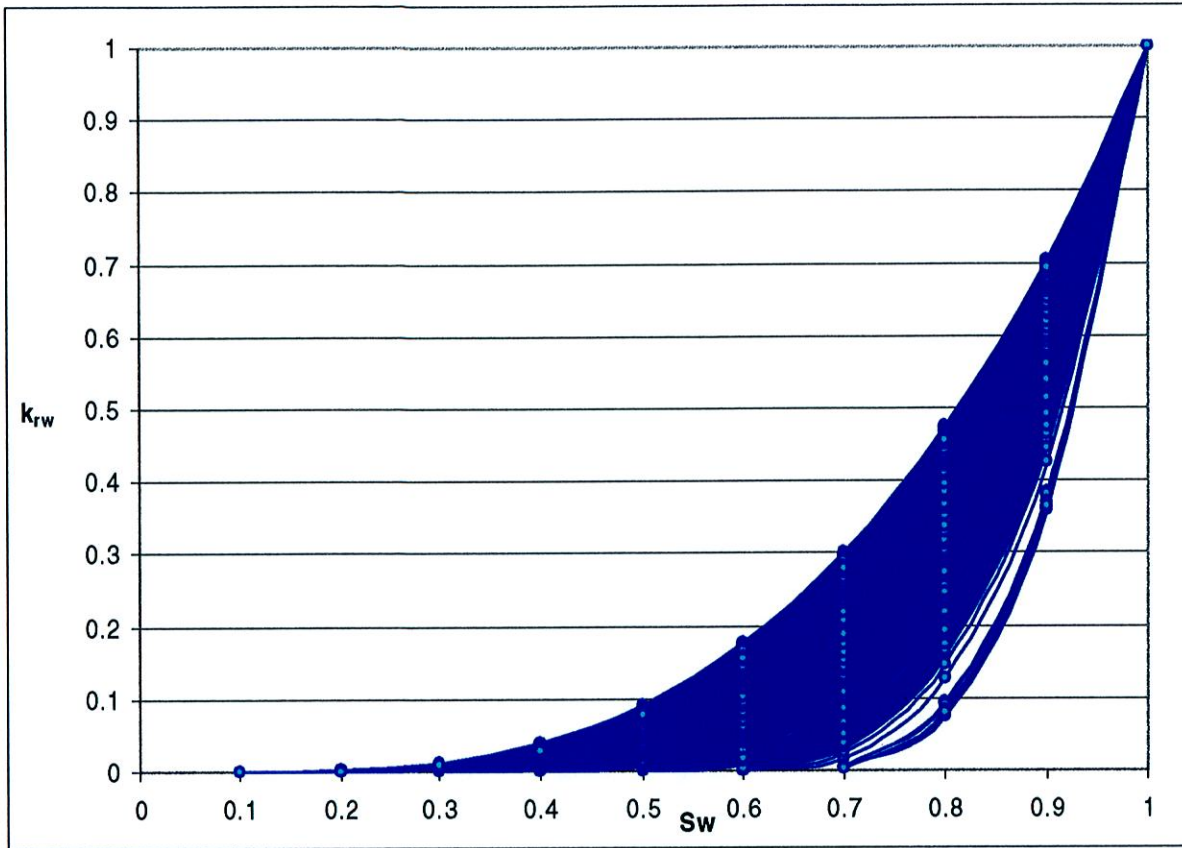
NOMENCLATURE:

BVI	: bulk volume irreducible
D	: diffusion constant
DTW	: dual wait time
F	: lithology factor
ϕ_e	: effective porosity
ϕ_i	: partial porosity
F_s	: pore shape factor
f_w	: fractional flow of water
γ	: gyromagnetic ratio
G	: gradient field
k	: permeability
k_{mw}	: relative permeability of the non-wetting phase
k_{rw}	: relative permeability of the wetting phase
P_c	: capillary pressure
P_d	: displacement (threshold) pressure
θ	: contact angle
ρ	: a measure of surface's ability to cause protons to relax
r_b	: pore-body radius
r_{pt}	: pore-throat radius
S	: surface area
C	: Scaling coefficient
R	: multiplier
w (subscript)	: wetting phase
nw (subscript)	: non-wetting phase
S_w	: wetting phase saturation
S_w^*	: normalized wetting phase saturation
S_{iw}	: connate water saturation
S_{or}	: residual oil saturation
σ	: interfacial tension
S/N	: signal to noise ratio
S_w	: wetting phase saturation
S_{wir}	: irreducible saturation of the wetting phase
T_2	: rate of decay of transverse magnetization
T_{2bulk}	: T_2 of bulk fluid
T_2cutoff	: a value of T_2 empirically related to capillary irreducible phase
TE	: inter-echo time
V	: volume

APPENDIX

Histogram

Statistic Results:

Average : 136.64912
Std   : 98.98801
Mode   : 693.09998
Median : 633.69995
Skewness: -0.19313
Kurtosis: -1.08007
# of Pts: 884
bins : 50
Bin width: 19.80000

Pore throat size, microns

Histogram

Statistic Results:

Average : 31,32920
Std   : 5,32201
Mode   : 29,50000
Median : 30,50000
Skewness: -0,25942
Kurtosis: 0,15252
# of Pts: 4037
bins : 50
Bin width: 1,00000

MPHE

Histogram

Statistic Results:

Average : 31.64085
Std   : 5.16969
Mode   : 30.50000
Median : 30.50000
Skewness: -0.26569
Kurtosis: 0.18768
# of Pts: 4037
bins : 50
Bin width: 1.00000

MPHS

14

Histogram

Statistic Results:

Average : 7.06994
Std   : 3.19583
Mode   : 6.75000
Median : 7.25000
Skewness: 1.74179
Kurtosis: 3.69554
# of Pts: 4037
bins : 50
Bin width: 0.50000

RBVI

Histogram

Statistic Results:

Average : 3.18266
Std   : 2.48644
Mode   : 3.75000
Median : 4.75000
Skewness: 1.30315
Kurtosis: 2.35360
# of Pts: 4037
bins : 50
Bin width: 0.50000

MBVI

Histogram

Statistic Results:

Average : 2106.06982
Std   : 2078.79663
Mode   : 65003.50000
Median : 63003.70312
Skewness: -0.79009
Kurtosis: 0.57845
# of Pts: 4036
bins : 50
Bin width: 1999.80005

MPERM, md

Histogram

Statistic Results:

Average : 1374.10815
Std   : 2243.21924
Mode   : 49005.10156
Median : 53004.70312
Skewness: -0.26217
Kurtosis: -0.03443
# of Pts: 4037
bins : 50
Bin width: 1999.80005

PURK

MAGNETIC RESONANCE
IMAGING LOG ®
PRODUCTIVITY ANALYSIS

Baker Hughes
Baker Atlas

DATE: 14-FEB-2002

ELEVATIONS:
KB
DF
EXC 1460.00   GL

COMPANY   YOUNGQUIST BROTHERS
WELL   INNOKALEE W #1
FIELD   INNOKALEE W.W.T.P
COUNTY   CHIW HILL   STATE FLORIDA
LOCATION:

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CENTER: HOUSTON	LOG ANALYST: M. ALTUNAY	DATE: 1-24-02
FIELD DATA	LOCATION:	ENGINEER:	DATE: 2-14-02	BHT

| FROM | TD | A | M | N | T2-Cutoff | De Model | |
| 1000 FT | 1890 FT | | | | 50 | 10, VAR, | BHT |

REMARKS

SYNTHETIC CAPILLARY PRESSURE, RELATIVE PERMEABILITY, FRACTIONAL FLOW OF WATER
CALCULATIONS ARE BASED ON EMPIRICAL CORRELATIONS. COATES PERMEABILITY IS
COMPUTED WITH C, M, N OF 10, 4 AND 2. PERM_C IS PURCELL'S PERMEABILITY BASED ON
SYNTHETIC CAPILLARY PRESSURE DERIVED FROM WRIL DATA. WBV IS OBTAINED WITH 50
MS CUTOFF T2WIL. SPECTRAL BVI AND BVWE ARE ALSO DISPLAYED. RSWV IS DERIVED FROM
SYNTHETIC CAPILLARY PRESSURE DATA AND IT IS INDEPENDENT OF T2CUTOFF TIME.

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WELL   INNOKALEE W #1
FIELD   INNOKALEE W.W.T.P
COUNTY   CHIW HILL   STATE FLORIDA
LOCATION:

FILE NO.:
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DATE   14-FEB-2002