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Permeability and Saturation Prediction Using NMR and Other Logs- A Clastics Case Study

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ABSTRACT: The current work reported focuses on permeability prediction and modeling water saturation using a novel technique demonstrated. To this end, in addition to NMR derived Timur-Coates and SDR permeability predictors, additional permeability predictors are computed, such as those based on characteristic length scale modeling from NMR, and on modal grain size (estimated using NMR and other open hole logs through a technique demonstrated in the paper), such as the RGPZ permeability predictor. Additionally mineral volumes based predictors are also computed, to be compared with data sets of formation tester pre-test data based permeability, for a robust best fit permeability at well point. Using certain attributes of NMR T2 distribution computable, such as maximum pore size along with total porosity computation from well logs, a Capillary Pressure-Water Saturation (Pc-Sw) transform is now derived as demonstrated in the main body of the paper. Computed Sw from the Transform is compared with SW derived level by level using NMR T2 distribution for refining the Pc-Sw transform mentioned above. The resultant Pc-Sw transform is a robust Sw predictor which can be used to validate the log based petrophysical analysis of other well sections that have similar Flow Zone Index (FZI) attribute. The extension into a 3D volume would now be possible, given a working porosity-permeability Transform, a porosity distribution in three dimensions, from seismic attributes that honors well point porosity distributions, and utilizing the Pc-Sw transform demonstrated in the main body of the paper for the case well section analyzed. Such propagation in three dimensions of Sw in addition to porosity and permeability would form the logical next stage of our work, once the efficacy of the current methodology is confirmed through work on other well sections which would be duly reported, in future.

Introduction

We initiate the discussion with the basic building blocks of the work namely permeability prediction and porosity estimation. We then move on to the theory and methodology of using porosity, permeability forward model and NMR T_2 distributions for estimating the fractal dimension of pore space and therefore computing a valid wetting phase saturation predictor for a drainage case. The work flows are demonstrated on two zones one each from two wells drilled off the West Coast of India and include generating flow zone specific forward model on water saturation versus height above Free Water Level in case of water wet clastic sections.

Porosity Estimation

Well log data inverted using multi-mineral petrophysical forward model and inverse modeling of model component volumes through error minimization technique. NMR and density log data simultaneously inverted (DMRP) using grain density computed from petrophysics and validated by ECS data based grain density to obtain inter-granular (total) porosity and arrived at best match between total porosity from DMRP and total porosity from petrophysical analysis.

Permeability Prediction

RGPZ Permeability Predictor

The ***characteristic length scale*** of voidage, denoted as **Λ**, is defined by

$\mathbf{2/\Lambda}= \frac{\text{Cumulative Surface Area of grains relevant of connected porosity}}{\text{Cumulative Connected Pore Volume}}$)= S/V=1/ρ$T_{2LM}$

Thus, $\mathbf{\Lambda = 2\rho T_{2LM}}$ρ = NMR Surface Relaxivity of the grain in m/sec)

It was derived by Glover et al.[1](2006),

$\mathbf{\Lambda} = \frac{R}{m*(1-F)} \approx \frac{R}{m*F} = \frac{d}{2mF}$ (When F >> 1, F stands for Formation Factor)

Thus, Effective grain size **'d' = 2* (Λ *m*F) = 2*((αρT_{2LM})/Υ)*(mF)**

The **RGPZ Permeability predictor** can be written as

$\mathbf{K = (d^2 \varphi^{3m}) / (4am^2)}$(where F= $1/\varphi^m$for m=1.8).

Permeability Prediction from NMR data
KTIM and KSDR are the standard NMR Data basedrobust Permeability Predictors. These have been calibrated with permeability computed from mobility from Formation Tester data to yield two more predictors of permeability in addition to the one discussed in the foregoing.

Geochemical Permeability Predictor
Finally geochemical permeability (KINT) based on mineral volumes computed from petro-physical processing has been estimated as

$$\mathbf{K= A_f[\frac{\emptyset^3}{(1-\emptyset)^2}]}\ \boldsymbol{exp}\sum_{i=1,2,\ldots,n} \mathbf{BiMi}$$

where $A_f$is a textural parameter n the number of mineral components in solids regime B_i is a permeability factor specific to a mineral species i and M_i the weight concentration of the mineral species I in the solids regime.
Geochemical permeability predictor specified as KINT has been calibrated with permeability computed from mobility from Formation Tester data through calibration of B_i and A_f to yield a calibrated predictor of permeability.

Representative Permeability
Weighted logarithmic mean of the different predictors of permeability computed as given above with higher weight to KTIM and KINT and relatively reduced weightage to KSDR and Permeability prediction using the RGPZ base equation as the starting base equation, has been computed, to obtain a robust permeability predictor denoted as PERM in this study, that is well validated by hard data of permeability from fluid mobility obtained using Formation Tester.

Wetting Phase Saturation using Brookes-Corey Equation (Forward Modeling)

In the context, of the foregoing, the next stage of the work reported is essentially concerns a new method of estimating core entry pressurePe and pore heterogeneity factor (using NMR, porosity and permeability predictors)that are fundamental to the definition of relationship between capillary pressure(Pc) and wetting fluid saturation(Sw)per Brooks-Corey model. We, on lines of Li et al (1985) bring out that modeling pore space as a fractal object leads naturally to a relationship between Pc & Sw anticipating the Brookes-Corey Relationship in a drainage cycle. We describe model of pore space as a fractal object the measure of the volume of which has been envisaged through spherical elementary units rather than cylindrical elementary units for obtaining pore volume.

We demonstrate that Mandelbrot Fractal Dimension and thereby pore heterogeneity factor relevant to Brookes-Corey relationship of Pc-Sw in a drainage cycle can also be obtained from an analysis of porosity permeability behavior of a porous medium.We also demonstrate a methodology for obtaining an estimate of Pe from analyses of NMR T2 Distribution, as also irreducible wetting fluid saturationSw_{irr}.

Flow Zone specific Pc-Sw Predictors have been demonstrated in the work and finally validated by the saturation height behavior seen from petrophysical processing results.

Theory and Methodologyof Forwarding Modelling Wetting Phase Saturation

Methodology adopted in the current work principally rests on estimation of Pe and S_{wirr} from NMR data and pore heterogeneity factor λ from porosity permeability behavior discussed further on. Reasoning on lines similar to those above (which, as can be noted, follow the line of reasoning presented by Li et al at reference 2,but with the 2 dimensional modeling of voidage as a bundle of capillaries of different radii and lengths replaced by a three dimensional model of interconnected pores) employed for understanding the rationale behind Brookes – Corey Relation when applied to poro–perm behavior, seems to lead to a method of estimating Df and hence λ from permeability vs porosity behavior as described below. This has been adopted in the current work for estimating λ.

Brookes – Corey Equation and the fractal nature of pore space:
Consider a stage in a Mercury Injection Experiment when VHg of Mercury is been injected. Let the pressure of Injection at that point be Pc
The pore space considered as replaced by Mercury is a Fractal object. Let radius of smallest throat radius penetrated by Mercury at this stage be denoted as r_c. Hence, $r_c$is related to Pc as

$$\mathbf{Pc}= \frac{2TCos\theta}{\mathbf{rc}} \text{ or } \mathbf{r_c}= \frac{2TCos\theta}{\mathbf{Pc}} \ldots\ldots\ldots\ldots\ldots(1)$$

Let Rc correspond to radius of pores having throat radius r_c . If we consider “units” of such pores, number of such units which can fill but not overfill the voidage which is now occupied by mercury, is given by

No. of units = $X1*Rc^{-Df}$

Where Df is the Mandelbrot Fractal Dimension of the Fractal object, namely voidage filled with mercury, referred to above. The result, of a measurement (with above units) of pore space filled by mercury at this stage of injection, V_{Hg} is given by

V_{Hg}= $(X1*Rc^{-Df})*\frac{4}{3}\times\pi Rc^3 = \frac{4}{3}*X1*\pi*Rc^{-Df} = \frac{4}{3}*X1*\pi*\gamma^{3-Df}\, r_c^{3-Df}$(say) and thereby

$V_{Hg}= X*r_c^{3-Df}$, where γ= PoreRadius/Throat Radius Ratio

$X=\frac{4}{3}*X1*\pi*\gamma^{3-Df}$(X, X1 are independent of Rc, r_c)

Substituting $r_c$from eqn. 1, We get

$V_{Hg}(r_c)=X*(\frac{2TCos\theta}{Pc})^{3-Df}$ ……………….(2)

Let $V_{Hg}(P_c)$ denote the actual volume of mercury injected up till when injection Pressure was Pc. Thus $V_{Hg}(P_c)$ is the ‘actual’ and $V_{Hg}(r_c)$ voidage measurement result using units of spheres of radius r_c to have a measure of $V_{Hg}(P_c)$.

Since the voidage filled by mercury is a fractal object, $V_{Hg}(r_c)$would be never equal to $V_{Hg}(P_c)$ no matter how small rcbe chosen (it is of interest here to note that $V_{Hg}(P_c)$ itself is a measure of voidage using mercury volume units). It is important to also note that had pore space been a euclidian object, then there would exist a sufficiently low r_c such that for all values of radius of the ‘measuring units less than r_c, $V_{Hg}(r_c)$ would equal $V_{Hg}(P_c)$). For the present case we assume $V_{Hg}(r_c)$ approximates to $V_{Hg}(P_c)$ for the range of P_c relevant.

We thus approximate as **VHg (P_c)=** $X*(\frac{2TCos\theta}{Pc})^{3-Df}$ (approx.)

If**VHg (P_c)** stands for cumulative mercury volume injected, up to injection pressure Pc (from zero to Pc) per unit volume of the medium and If SHg (P_c) stands for mercury saturation at this stage of injection and ∅ for porosity,

VHg (P_c) = $\emptyset\times SHg\,(Pc)$

SHg (P_c)= $[X*\frac{(2TCos\theta)^{3-Df}}{\emptyset}]*Pc(r_c)^{-(3-Df)}$

SHg (P_c)= $Z*Pc(r_c)^{-(3-Df)}$ **where** $Z=X*\frac{(2TCos\theta)^{3-Df}}{\emptyset}$ …………….(3)

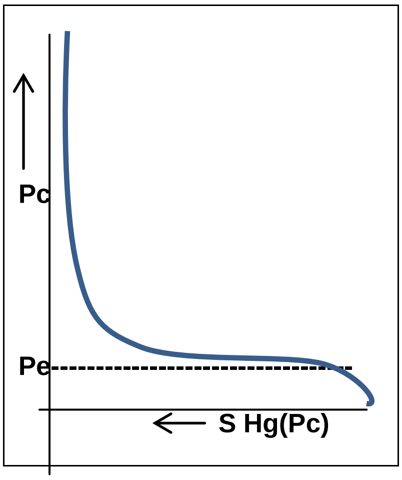
In real capillary pressure Injection experimentsthere exists anSHg_{max}given by

$SHg_{max}=\lim_{Pc\to\infty} SHg\,(Pc)$

An arbitrarily largePc_{max} would make

$SHg(Pc_{max})= SHg_{max}$to a good approximation.

The value of Pc with SHg(Pc) very small (equal to that of voidage of pores having largest throats), would also exist, which is denoted as Pe



Let SHg(Pe) be denoted as Ɛ

Since SHg(Pc) doesn’t tend to 1 but to SHg_{max}, at high Pc Values, relation (3) above should be modified to relation

$(SHg_{max} - SHg\,(P_c))=Z*(Pc(r_c))^{-(3-Df)}$

SHg(Pe) = Ɛ

Hence we have

$SHg_{max} - \varepsilon = Z*Pc(r_c)^{-(3-Df)}$

$0 = Z*Pc(r_c)^{-(3-Df)}$ as$SHg(Pc_{max}) = SHg_{max}$

And $Z=\frac{(SHgmax\ -\varepsilon)}{(Pcmax^{-(3-Df)}-Pe^{-(3-Df)})}$

Leading to

$[SHg_{max} - SHg\,(P_c)]=\frac{(SHgmax\ -\varepsilon)}{(Pcmax^{-(3-Df)}-Pe^{-(3-Df)})}*[Pc(r_c)]^{-(3-Df)}$

Understanding that for the case of non-wetting fluid displacing wetting fluid and neglecting Ɛ as too small in comparison to SHgmaxand replacing SHgmaxwith (1-SW_{irr}) and SHg (P_c) with (1-S_w) and substituting in the above equation we get

$[S_w - SW_{irr}] = (1-SW_{irr})*\{[Pc(r_c)]^{-(3-Df)}]/[Pcmax^{-(3-Df)} - Pe^{-(3-Df)}]\}$

Dividing numerator and denominator of R.H.S by $Pe^{-(3-Df)}$ and then dividing throughout by (1-SW_{irr}) we get

$(S_w - SW_{irr})/(1-SW_{irr}) = \{[Pc(r_c)/Pe]^{-(3-Df)}\}/\{[(Pcmax/Pe)]^{-(3-Df)} - 1\}$

Since voidage is a fractal object and if Euclidian would have a dimension of 3.0, and since a fractal, would have fractal dimension less than 3.0 and consequently, Df would always be less than 3.0 and therefore 3-Df always greater than zero.
Since $Pe \ll Pcmax$ would always be true$[(Pe/ Pcmax))]^{(3-Df)}$ would be negligible in comparison to 1.0 in value. Taking note of this we see that the above equation simplifies to
$\mathbf{(S_w-SW_{irr})/(1-SW_{irr}) =\{ [Pc(r_{c]})/Pe]^{-(3-Df)}\}}$ approx..
Denoting L.H.S by S_w^* and (3-Df) by λ we can write
$\mathbf{(S_w^*)^{1/\lambda} = Pe/ Pc}$ **or**
$\mathbf{Pc = Pe*(S_w^*)^{1/\lambda}}$ **which is Brookes-Corey Relation.**

Fractal Dimension of pore spaceandPorosity - vs- Permeability behavior:
Again we consider the number of pores of radius R, which can fill but not overfill voidage as given by $\mathbf{N(Ro)= XRo^{-Df}}$.
The cumulative volume of all such pores would be
$\mathbf{\Phi= N(Ro)*\frac{4}{3}\times \pi Ro^3 =X1*\frac{4}{3}\times \pi Ro^{3-Df} = XR_o^{3-Df}}$ **(say)**
Let ř stand for a representative radius of pores which when composited to make Φ, the porosity give rise to same **Surface/Volume** ratio as the rock.
In that case, Permeability can be written as
$\mathbf{K= \frac{a}{F}\check{r}^2}$**, and** $\mathbf{\check{r} = (\frac{FK}{a})^{0.5}}$where F denotes Formation Factor
Let Φ stand for a pore space measure with ř as the measure of the 'unit' used for measurement (sphere of radiusř) then Φ would be related to ř as
$\mathbf{\emptyset = X(FK/a)^{(3-Df)/2}}$
Understanding that $F= \Phi^{-m}$, taking logarithms both sides and rearranging we get
$\mathbf{(2/(3-Df) + m)\log \Phi = \log([X^{2/(3-Df)}]/a)+\log k}$
Above relation implies that a **plot of log k-log Φ would be a straight line of slope (2/(3-Df)+(m)) from which fractal dimension of pore space, Df can be obtained and thereby Brookes-Corey heterogeneity factor λ. Fig 2 & 5** elaborates the **λ=3-Df** as slope of the above-said cross-plots of two flow-zone studied, giving a value of around 0.28 for **λ.**

Estimation ofPe, the Entry Pressure:

Entry pressure Pehas been estimated from 98percentile of the pore size distribution by twomethods.

Method1:
NMR T2 bin porosity for the classes (bins) CBP3 (3ms-10ms), CBP4(10ms-33ms), CBP5(33ms-100ms), CBP6(100ms-300ms) and CBP7(300ms-1000ms)have been used after correction for Wait Time and Hydrogen Index for non-wetting phase, for computing the value of T2 which correspond to 98 percentile as
$T_2= T_{2LM} + a*SD$ where T_{2LM} stands for log-mean T_2 of Bins 3 to 7
Where SD is Standard Deviation computed as
$SD = \{\sum_3^7 (Ci * CBPi)/(\sum_3^7 CBPi)\}^{1/2}$
Here, "$CBPi$" stands for bin porosity of bin *i*, and Ci is square of deviation of thegeometric mean of the T_2 values defining the left edge and right edge of T_2 class 'i'(i=3-7) with respect to Log-Mean of T2 values of the T_2 classes 3-7 , and "a" is a co-efficient adjusted as per shape of T2 envelope of bins 3 to 7.

Method2:
$\mathbf{Let\ d98 = 0.98(\sum_1^6 CBPi)]^{1/2}}$
$\mathbf{d1 = \sum_3^6 CBPi\ ,\ d2 = \sum_3^5 CBPi}$
x1= [(d98-d1)/CBP7]*700
y1 = [(d98-d1)/CBP6]*200
x = 300+x1
y = 100+y1
Then, let T_2=x if (d89>d1), or else let (T_2=y)
T_2has been chosen as the mean of the T2 values obtained above.The chosen T_2has been converted to throat size representative of Entry Pressure Pe as follows.
Maximum value of pore throat available at a level has been computed as
Maximum Throat Radiusr_{thmax}= a*ρ*T2 where
ρ is relaxivity of grain ($3.5*10^{-5}$mt/sec used) and 'a' is a shape factor converting specific surface area to throat dimension.

Entry Pressure Pe has been computed as
Pe= (2Tcosθ)/r_{thmax} where T is Interfacial Tension of the wetting fluid-non-wetting fluid interface and θ is Angle of Contact

Irreducible Saturation of Wetting Phase:
Micro-porosity has been estimated as sum of NMR bin Porosities CBP1(Cumulative Porosity of 0.3ms-1.0ms Bin) and CBP2(Cumulative Porosity of 1.0ms-3.0ms Bin).
Irreducible Saturation of Wetting Phase has been estimated as
S_{wirr} = (Micro-porosity/ Total Porosity)

Work Flow implemented:
Flow Zones considered as per Flow Zone Index (FZI) computed as

$$FZI=\left[\frac{0.0314\sqrt{k}}{\emptyset}\right]/\left[\frac{\emptyset}{1-\emptyset}\right]$$

Flow zones having fairly uniform FZI selected for case study. (Present paper reports work on two flow zones selected from two wells both situated in shallow water off the west coast of India).
Mandelbrot fractal dimension Df and therefrom, pore heterogeneity factor computed for individual flow zones by cross plotting log k against log Φ. Straight line trends have been obtained indicating applicability of uniform fractal dimension for a flow zone. Fractal dimension of would be a straight line of slope **(2/(3-Df)+(m))** from which fractal dimension of pore space, Df can be obtained and thereby Brookes-Corey heterogeneity **factor λ**. The relevant cross plots are presented at plates 1 and 2 respectively. **The fractal dimensions are respectively 2.72 and 2.74** for the two flow zones for which the work flow has been demonstrated.
Pe computed level by level has been indicated at **track 8** of the composite display **Fig 1 & 4** for the two flow zones studied.
Irreducible water saturation (water assumed to be the wetting phase – rock assumed to be water wet) S_{wirr} as
S_{wirr} = CBP1=CBP2 (Micro - Porosity bins porosity values CBP1 and CBP2 together representing porosity within pores represented by NMR T2 falling within the interval 0.3ms-10ms
Free Water Level obtained from Formation Pressure vs Depth plots as intersection of hydrocarbon and water lineswhere well penetrated a contact. Correlation from Free Water Level seen from other wells nearby to obtain Free Water Level depth per the Measured Depth of case well in case contact happens to beun- penetrated by the case well.
Capillary Pressure Pc evaluated as
h = (MD-FWL) m
Pc = h(ρ_w-ρ_g)*1.42112432 psi
Where MD is Measured Depth m and FWL is Free Water Level m
And $\rho_w$and ρ_g respectively stand for water and gas densities in g/cc units at formation temperature (for the candidate zones studied the non-wetting phase is gas)
Water Saturation SW* (Water Saturation normalized for irreducible water saturation) computed as
SW* = $(Pe/Pc)^{1/\lambda}$ where λ = 3-Df earlier computed and Pe Pc computed earlier on.
Actual Water Saturation in total porosity Sw is computed as
Sw = S_{wirr} + (1- S_{wirr})Sw*
Sw against depth stored for the Flow Zone studied as a Forward Model of Wetting Phase Saturation versus Height above FWL behavior.
A representative S_{wirr}a Flow Zone computed as logarithmic mean of the S_{wirr} data set of the Flow Zone. A representative Pe is similarly computed representative of the Flow Zone.
Using the equations above for SW* and SW, but with Pe and S_{wirr} now the representative values, overlays of Pc-Sw representative of Flow Zones studied, generated and also stored as a Tables Flow Zone wise. (Examples for the cases of the Flow Zones study presented are available at plates 3, 4).

Discussion of Results
Validation of total porosity from petrophysical processing by the total porosity from DMRP is available on **track 4**in **Fig 1and 4**through overlay of the two porosity data sets. Validation of **Representative Permeability** by permeability computed from mobility data as Formation Tester Pre-Tests based station readings is available **at track 6, next to Petrophysical Multi-mineral Volumetrics**. The degree of validation of both porosity and permeability data sets demonstrated, brings out the robustness of these data sets qualifying them as valid input channels to drive the generation of a valid Sw Forward Model.

Forward model of Sw against Measured Depth has been overlaid on Sw computed from log data inversion **at track 7** of the respective composite presentations in respect of the relevant intervals analyzed in**Fig 1 & 4**. It is seen that the match between the forward model and the Petrophysical computation in respect of Sw is very good. This establishes the usability of the work-flow as a valid prediction work flow in respect of wetting fluid saturation as a culmination of a drainage cycle.
The **Flow Zone Representative Pc-Sw curve** has been presented individually in **Fig 3&6** for each of the two zones studied. This presentation also has the actual Sw from Petrophysics also plotted with Pc calculated from Height above **Free-water Level (FWL)**. It is seen that the bulk of the points plot on or close to the respective Pc-Sw overlays. There are some points plotting away from overlay(s) which represent internal heterogeneity. Finer Flow Zone Demarcation can be attempted in future when this work flow gets applied for validation in a multi-well context.
Using seismic attributes especially sweetness attribute as a guide it is possible to propagate forward models of saturation height behavior to areas un-penetrated by wells and have 3-D forward models of saturation.
The match of forward model with Sw from petro physics is also a testimony to the robustness of permeability and porosity predictors as well as the methodology of Fractal Dimension Estimation. This opens up a possibility of making Fractal Dimension as an additional Flow-zone Attribute as well.

Conclusions

A methodology of forward modeling wetting fluid saturation which relies exclusively on log and NMR data has been demonstrated as valid through comparison with robust petro physics generated results.
Fractal Dimension of pore space is brought out as an important additional attribute which defines Flow Zones in addition to the conventional attributes of porosity and permeability.
Forward model of Pc-Sw behavior as a representative behavior for a defined Flow Zone is demonstrated.
Seismic attributes can guide propagation away from well bores of the Fractal Dimension of pore space in addition to the Irreducible Wetting Phase Saturation and Entry pressure away from well bores and thereby lead to finer Flow Zone definition, and more robust prediction of wetting fluid saturation in three dimensions.
The importance of the above cannotbe over emphasized given the fact that robust forward models on Sw are central to useful Relative Permeability Models generation, which in turn is central to Reservoir Simulation.
Validation of the results of the work flow is a validation of the methodology employed to generate robust predictor of absolute permeability demonstrated in this study.

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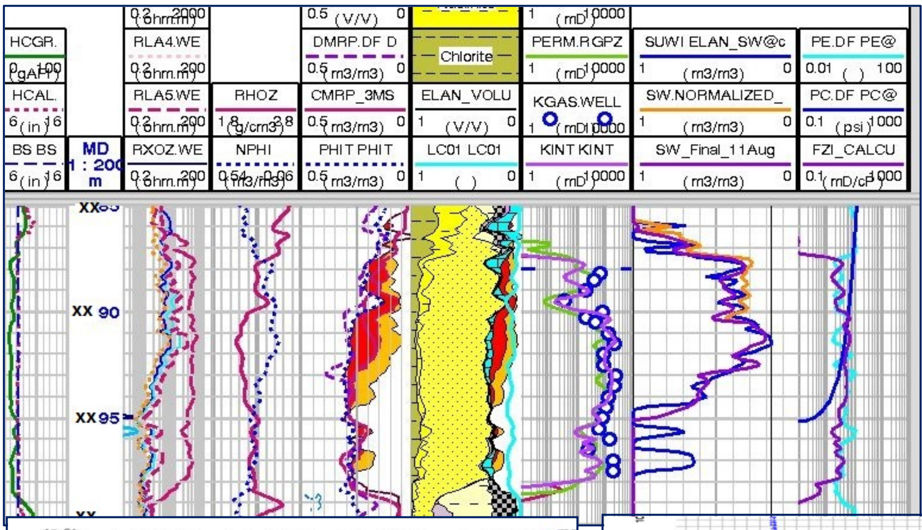

Fig1:Well-A Integrated Petrophysical Analysis with well validated Permeabilities & robust Wetting-phase Saturations shown

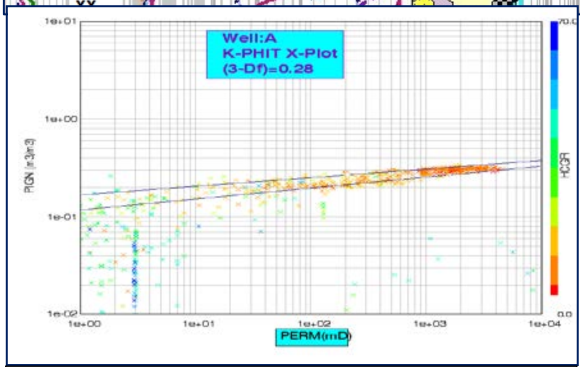

Fig2: Perm-PHIT plot: Slope of Sand Packet= λ~ 0.28

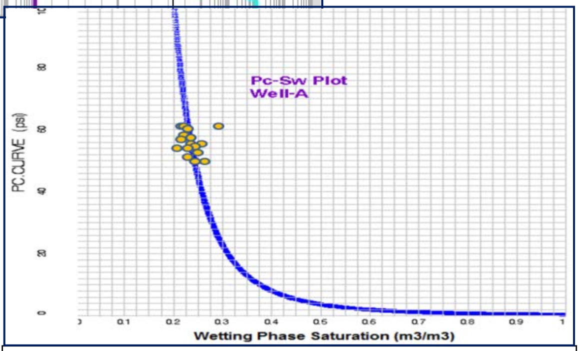

Fig3: Pc-Sw plot-Points above free-water level cluster well on overlav

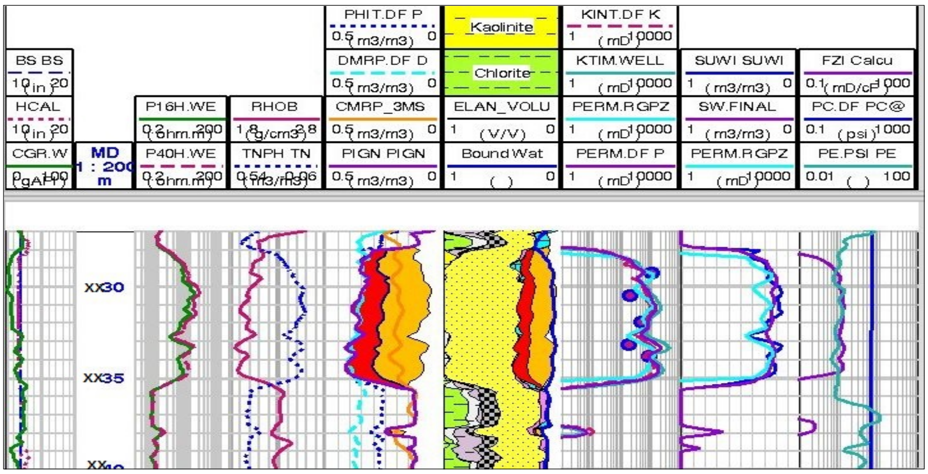

Fig4:Well-B: Integrated Petrophysical Analysis with well-validated Permeabilities & robust Wetting-phase Saturations Shown

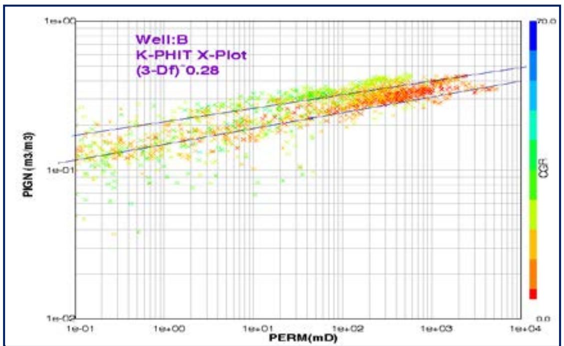

Fig5: Perm-PHITplotWellB:Slope of Sand Packet=λ~ 0.28

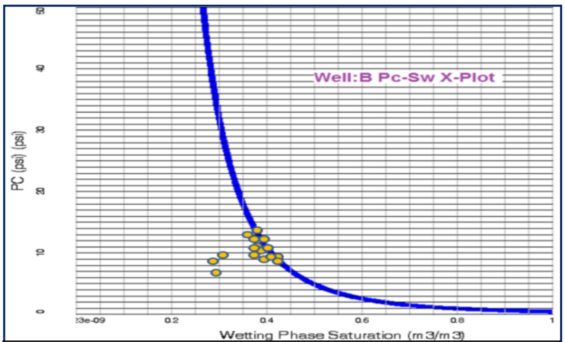

Fig6: Pc-Sw plot of Well B-Points above free-water level cluster on overlav with minor