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POROSITY SYSTEMS AND PETROPHYSICAL MODELS USED IN FORMATION EVALUATION

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Summary

The various porosity concepts and associated petrophysical models are briefly reviewed in the light of the

(i) basic requirements for reservoir-evaluation and simulation,
(ii) nature of the core and log data used,
(iii) petrophysical models employed and the
(iv) extent to which core and log data can be integrated/reconciled and the objectives under (i) met.

Emphasis is placed upon the basic characteristics, merits and limitations of the "total" and "effective" porosity concepts and related petrophysical models used in the evaluation of shaly sands. The large variety of models employed in the North Sea and world-wide (and the variety of results produced by these models on the same log data set) is a source of confusion and incompatible assessment of reservoir potential. The consequences of this for prospect evaluation, field development decisions (especially in the case of marginal fields) and equity determinations can be far-reaching.

The review is concluded with the suggestion that the hydrocarbon-in-place and productivity can be most reliably and convincingly evaluated, on the basis of models built upon the concept of total porosity.

A brief outline of such a method (using the Waxman-Smits model) is provided in the Appendix.

1. INTRODUCTION (VG1)

The previous speakers have already reviewed (i) the geological aspects of porosity, the large variety of pore structures created by the sedimentary and diagenetic processes, (ii) the various core analysis procedures employed to "measure" the in-situ porosity, (iii) the response of the various logs to "in-situ" porosity (and the multitude of bore hole environmental effects, as well as the effect of lithology [clay] and hydrocarbons on log response) and (iv) some aspects of the statistical treatment of core and log data in porosity assessment.

Seemingly, we have all ingredients to start on an example of well evaluation using core and log data. This indeed is the next stage in our programme.

However, before the examples are presented (which will be carried through to the "Saturation" seminar) it is opportune to consider Formation Evaluation in its totality, and ask ourselves the question, how the POROSITY ASSESSMENT - the subject of our present seminar - affects the estimate of SATURATION and PERMEABILITY - the subjects of the next two seminars - and reservoir modelling/simulation in general.

I would like to give, therefore, a glimpse of the overall aspects of formation evaluation and the crucial role of porosity in it. We do that by highlighting the

- basic requirements for formation evaluation/reservoir simulation
- porosity concepts employed ($Ø_T$, $Ø_E$ in particular)
- porosity definitions from cores and logs
- models employed for S_w and k assessment
- and how the $Ø_E$ and $Ø_T$ models satisfy the requirements.

2. EVALUATION REQUIREMENTS (VG2)

The ultimate goal of formation evaluation is the estimate of

(i) hydrocarbon-in-place (HIP) for reserves assessment, and
(ii) productivity (permeability)

The parameter porosity has a crucial role in all aspects of the assessment. Not only does it have a primary and dominant role (as the quantitative expression of storage capacity of the rock) in the equation

$$HIP = A.H. (N/G).Ø. (1 - S_w)$$

but it also affects the estimate of HIP indirectly via S_w and N/G (via Ø-cut off related to permeability) which are all porosity dependent.

Sound assessment of the porosity on the basis of data from both cores and logs, in a manner compatible with (i) the petrophysical (S_w) model employed and (ii) with all other porosity related parameters which are ultimately fed into a numerical reservoir simulator (e.g. N/G ratios, capillary pressure - S_w relations, k-Ø and relative permeability - S_w relations, etc) *is absolutely essential to obtain meaningful results.*

All these may sound self evident but I am sure that there are multi-disciplinary teams (in any company) where the reservoir engineer is not quite aware of the nature of the porosity and saturation data provided by the log analyst, or the log analyst may not fully appreciate the nature of certain core analysis data used in the model. The result of this could be, for instance, that the log evaluation results provided in the effective porosity system, do not match the core data provided in the total porosity system (e.g. Ø, Cap.curves, k-Ø relation etc.) and therefore either the log or the core analysis results are declared unreliable and discarded.

3. PROBLEM OF INCOMPATIBLE RESULTS (VG3)

The above problem may remain an internal company affair; the people involved in it may choose to ignore it or to resolve it somehow (e.g. by convincing each other that consistency of $\emptyset$ definition is, after all, crucial for meaningful results and making a new evaluation).

Such problems become much more exciting (or, rather to say, troublesome) when evaluation results provided by various companies, consultants or service companies on the same well or field have to be compared with each other in order to arrive at certain decisions (e.g. selling/buying a prospect, field development, equity, etc.). The evaluations may turn out to be all different (VG3); ref. 3,6.

The basic underlying reason for the discrepancies is usually the different porosity concepts and related petrophysical models employed in the evaluations.

Which evaluation shall we believe? I suggest, the one which has made optimum use of all core and log data available, reconciled both data sets and the results corroborated with additional core data (e.g. cap curves) and production test data.

I submit that this can best be achieved by strict adherence to the total porosity system.

In the following I will attempt to substantiate this statement.

4. POROSITY CONCEPTS (VG4)

There are at least three porosity concepts which are widely known and used in formation evaluation:

(i) Traditional TOTAL POROSITY ($\emptyset_T$)

- including all fluids

(ii) Traditional EFFECTIVE POROSITY ($\emptyset_E$)

- excluding shale-water, i.e. $\emptyset_E = \emptyset_T - \mathrm{Vsh}\ \emptyset_{Tsh}$

(iii) Q_v related EFFECTIVE POROSITY ($\emptyset_{E(Qv)}$)

- excluding anion-free clay-bound water (CBW)

The last one has two different definitions:

one according to the work of Hill, Shirley and Klein (Ref. 8):

$$\emptyset_{E(HSK)} = \emptyset_T\ (1-0.6425\ S^{-0.5} + 0.22)\ Q_v$$

where S - is salinity in g/l NaCl
Q_v - is CEC/PV (meq/ml)

the other one according to the Dual Water Model (DWM) definition of Clavier, Coates and Dumanoir (ref 5):

$$\phi_{E(CCD)} = \phi_T(1 - \alpha V_Q . Qv)$$

where αV_Q = f(salinity, temperature)

The above concepts already illustrate the complications around the definition of ϕE. The various ϕE definitions, concepts and determination techniques yield different ϕE values. Furthermore, all ϕE determinations (either via core analysis or log interpretation) are indirect and, in fact, based on ϕ_T. ϕ_T is apparently the only unambiguous porosity concept, and a rock property which (using the appropriate procedures) can be measured on cores and assessed from logs.

5. POROSITY CONCEPTS AND PETROPHYSICAL MODELS (VG5)

In spite of the difficulties to unambiguously define ϕ_E, the concept of "effective" porosity can be useful in the assessment of permeability and certain aspects of fluid flow in shaly sands.

VG5 is a schematic illustration of a formation ranging from clean sand to shale, and shows the relationship between the various porosity definitions discussed above.

Efforts over the last 30 years to integrate the effective and total porosity concepts with core and log analysis fall into two major categories and resulted in the so-called "traditional ϕ_E/V_{sh} models" and the "ϕ_T/Q_v models".

(i) ϕ_E/V_{sh} models

The traditional ϕ_E/V_{sh} models are essentially of "trial and error" origin and mainly log interpretation oriented using the following reasoning: Shales are such fine-grained sediments that they have porosity but no permeability to allow entry of hydrocarbons or contribute to fluid flow. Hence the (total) porosity of a shaly sand should be discounted by the porosity of the shale present in it, and this defined as effective porosity:

$$\phi_E = \phi_T - V_{sh}\, \phi_{Tsh}$$

However, the Archie saturation equation (already yielding too high S_W values even with ϕ_T) would lead to unrealistically high S_w value with this (lower) porosity. Many saturation equations - mostly using shale conductivity proportional to V_{sh} (i.e. V_{sh}/R_{sh}) - were, therefore, developed to compensate for shale conductivity effects in saturation calculations; an example is shown in VG5.

Whilst the traditional definition of effective porosity appears to be a pragmatic one, there is no scientific justification and experimental support for the many methods that have been proposed to quantify ϕ_E, V_{sh} and S_{WE} using ϕ_E/V_{sh} models. Furthermore, these models cannot be integrated with core analysis data since neither ϕ_E nor V_{sh} (and hence the ϕ_E - related S_{WE} and permeability)/ measured on cores.

(can be)

(ii) $\emptyset_T/Q_v$ models

The $\emptyset_T/Q_v$ models have the advantage that (a) both $\emptyset_T$ and Q_v can be measured on cores (facilitating integration/reconciliation of all porosity related input and output parameters with core data) and (b) the validity of the models can be judged on the basis of the scientific considerations and supporting laboratory experiments on which they are based.

The common feature in the $\emptyset_T/Q_v$ models, which distinguishes them from the $\emptyset_E/V_{sh}$ models, is the recognition that not the amount of shale, but the cation exchange capacity (or Q_v = CEC/total pore volume) is the critical parameter for the quantification of both clay-conductivity (for saturation calculation – ref. 23,5) and clay-bound-water (ref. 8,5).

The amount of CBW defined via Q_v is less than $V_{sh}\emptyset_{Tsh}$ because only the water adsorbed on the clay mineral surfaces (proportional to CEC) and the water required for the hydration of clay counter-cations (CEC) is included; capillary bound ("far") water present in the shales is excluded. The Q_v – related effective porosity may be used to infer effective saturation (from $\emptyset_{E(Qv)} \cdot S_{hE} = \emptyset_T \cdot S_{hT}$) and employed in the assessment of permeability.

Permeability/productivity assessment requires consideration of both the Q_v-related effective porosity (ref. 10, 12) and the shale distribution (ref. 11). It is suggested that shale layers (be it in the form of massive beds or fine laminations beyond the vertical resolution of the logging tools) are entirely excluded from net pay. These layers or laminae do not contribute to fluid flow because also their so-called "far"-water is immobilised by capillary forces. In the intervening shaly sand layers, with dispersed or finely distributed structural clay in them, the capillary forces are governed by the pore structure of the sand and can be much weaker than in the fine-grained shales. In these sands, therefore, only the Q_v related CBW should be excluded; i.e. $\emptyset_E(Q_v)$ should be used in fluid flow assessment in water saturated sands (in pay zones [Soi-Sor] may provide a more direct way of assessing the part of pore volume contributing to flow).

(iii) Application of the $\emptyset_T/Q_v$ models

Referring to the Waxman-Smits saturation equation Lavers et al state in their 1974 paper (ref. 25) that "the historical problem in applying this equation is in finding a reliable way of estimating cation exchange capacity, CEC, hence Q_v. At present, it is only possible to do this in the laboratory using cores or sidewall samples; there is not yet a logging method of measuring Q_v, although several approaches are under investigation". This statement applies to any $\emptyset_T/Q_v$ model in use and is, basically, still valid today. However, several practical approaches have been developed over the years, for the application of the W-S model in particular, which have greatly alleviated the problem. Apart from the "local empirical relationships" that may be defined between porosity and Q_v (as shown by Lavers et al), new log analysis approaches (e.g. "normalised Q_v – ref. 10) are now also available to estimate Q_v and solve the Waxman-Smits equation in the absence of core data. These developments have eliminated the advantage of the "logs only" evaluation capability of the $\varnothing_E/V_{sh}$ models without compromising on the greatest merit of a proper $\varnothing_T/Q_v$ model: the capability to integrate/reconcile core and log data.

Unfortunately, however, owing to the complexities of shaly sand evaluation, easy misunderstanding and misuse of the various concepts and definitions may still lead to significantly different results using the various $\varnothing_T/Q_v$ approaches. Sound definition of $\varnothing_T$ from both cores and logs is one of the most fundamental but often mistreated requirement. Some aspects of this will be examined below.

6. <u>POROSITY FROM CORES (VG6)</u>

One of the crucial aspects of core porosity measurement (using either the resaturation or the gas expansion technique) is <u>sample preparation</u> before the measurement.

There are two basic approaches. The difference between the two approaches is the extent of drying of the core plugs after cleaning.

Many people believe that gentle drying at 60°C in a humidity controlled oven (normally at 40 degree relative humidity) results in effective porosity. It is indeed demonstrated (by Bush and Jenkins, ref 4) that a certain amount of CBW (correlatable with CEC) is retained this way. However, by comparing this amount of water with the "anion-free water" defined by Hill, Shirley and Klein (ref. 8) or by Clavier, Coates and Dumanoir (ref. 5) (and, of course the even greater amount of shale water, used in the traditional $\varnothing_E$ definition) it becomes clear that the amount of clay associated water retained by this drying technique is too small. Therefore, the resulting porosity is somewhere between $\varnothing_T$ and $\varnothing_{E(Qv)}$.

It has been abundantly proven in the literature (ref 13,16) that drying the core plugs at 105–110°C (in a vacuum oven for 1–3 days) removes all interstitial and absorbed clay-hydration water without damage to the <u>composition</u> of the solid clay crystals*. The routine porosity measured this way on cores is, therefore, total porosity, $\varnothing_T$.

Applying higher temperatures to the rock is not advisable as some types of clay crystals themselves will start to deteriorate irreversibly by loosing *OH groups, or solid organic constitutents of the rock (sometimes present* in minor amounts - frequently associated with the clay fraction) begin to decompose.

Although, as indicated above, the core porosities obtained at 60°C and 40° humidity are relatively close to $\varnothing_T$, the discrepancy between the two porosities (which is increasing with increasing shaliness) may significantly affect all porosity related parameters. Insufficient drying results in too low $\varnothing$, ϱ_g k_{air}, m, n, "Sw" in cap.curves and too high Qv compared to their $\varnothing_T$ equivalents.

Footnote:

* Damage to clay-<u>morphology</u> may occur in certain shaly sands containing, e.g. delicate illite fibres (ref 14,21) as a result of the drying process (even at lower temperatures). However, this mainly affects the pore-structure (and related parameters like permeability) and hardly affects the porosity value itself. "Critical-point-drying" and "critical-point-wetting" techniques can be used in such cases to successfully measure parameters sensitive to clay morphology.

7. POROSITY FROM LOGS (VG7,8,9,10)

With the density log one is not able to distinguish between water in the bigger pores (the major contributors to hydraulic conductivity, i.e. permeability) and water in the smaller pores in the shaly/clayey parts (with practically no contribution to permeability). In fact, if the clay crystals have approximately the same grain density (2.65-2.70) as the sand, the total porosity can be directly determined from the density log. By calibration of the density log to core measured ϕ_T and ρ_m the appropriate ρ_f can be defined (as shown in the appendix and VG8) and ϕ_T calculated from the log: $\phi_T = (\rho_m - \rho_b)/(\rho_m - \rho_f)$. This is the most fundamental approach to ϕ_T determination from log response.

The latest probabilistic/statistical log evaluation approaches offer another way of deriving total porosity as $\phi_T = 1 - \Sigma V_{mi}$, where V_{mi} represents the fraction bulk volume occupied by the various "dry" minerals, including $V_{cl(dry)}$ (or individual clay-mineral fractions) observed in formation samples.

Another way of ϕ_T derivation from logs is to define ϕ_E the traditional way using the individual porosity logs or combination of porosity logs and add to ϕ_E the amount of shale-associated water ($V_{sh}\phi_{Tsh}$), estimating ϕ_{Tsh} on the basis of core and/or density log data.

The last mentioned approach involving ϕ_E is obviously an indirect one and should be avoided whenever possible, since it has to make reference to properties of adjacent shale beds as seen by the various logging tools, estimate V_{sh} and assume that the shale effect in the sand is proportional to V_{sh}. This approach may nevertheless may be useful in cases when the density log is unreliable (e.g. due to wash-outs, etc.) and the clay mineralogy in the sands and shales is similar (a check on this is possible - ref. 10).

In this context it may be worth mentioning that the response of the Sonic Log is probably the most unpredictable: the effect of shale distribution, hydrocarbon and compaction are all difficult, if not impossible, to define.

Special mention should also be made of the Neutron Log response in shales and shaly sands. The strong deviation of this log compared to the density log ($\phi_N > \phi_D$)in these rocks is not due to the (liquid) water associated with the clays but due to the "lithology" effect of the solid clay crystals. The *hydrogen built into these crystals in the form of OH groups are also "seen" by* the neutron log. This hydrogen content may be appreciable as shown in VG 9.

The difference between the neutron and density log derived porosity (related to the Hydrogen Index of the dry clay mineral fraction) may, in fact, be exploited to infer $V_{cl(dry)}$ and - in combination with resistivity logs - Qv (CEC/PV), and from Qv the amount of clay-hydration water and effective porosity, $\phi_{E(Qv)}$; and all this pertaining to the shaley sands themselves, without requiring reference to adjacent shale beds (ref 9, 10, 17).

In view of the above, it should also be clear that total porosity cannot be derived from the average of the density and neutron-log porosities as suggested in Clavier's original paper on the DWM and used by some log analyst (inter alia in CYBERLOOK ref. 2), since

$$\phi_T \neq \frac{\phi_N + \phi_D}{2} = \phi_{D/N(x\text{-}plot)}$$

The above approach (also referred to as the so called density/neutron crossplot porosity approach) always leads to an overestimate of ϕ_T in shaley sands.

A comparison of all porosity definitions discussed above is presented in VG10.

8. SATURATION MODELS (VG11)

Since the next seminar will be devoted entirely to this subject, we can be brief; for a comprehensive overview the reader is referred to Worthington's paper - ref 24.

All existing saturation equations are based on Archie's (1942) formula, which is applicable to clean formations where $\phi_T = \phi_E = \phi$:

$$S_w = (a\phi^{-m}.Rw/Rt)^{1/n}$$

As already mentioned, two major groups of equations were developed during the last 30 years to estimate water saturation in shaly sands. One group of equations/models is based on the total porosity (ϕ_T) system (e.g. the Waxman-Smits and Dual Water Models), the other group on the traditional effective porosity ($\phi_E = \phi_T - V_{sh}\phi_{Tsh}$) system (e.g. Modified Simandoux, Total Shale, Indonesia, Nigeria, etc., equations).

The basic difference between the two groups of models is indicated in VG11:

- the ϕ_T models retain the basic Archie equation with the appropriate pore-geometrical parameters for the total pore space (e.g. m*, n*) and use the cation exchange capacity per total pore volume (Qv = CEC/PV) to account for clay-conductivity effects. In doing so both the W-S and the DW models attempt to calculate an equivalent water conductivity (as a function of Rw, clay-counter ions present in the water phase and temperature) for use with the simple Archie equation. All parameters used (e.g. m*, n*, Qv, ϕ_T) can be measured on cores, and the resulting S_{WT} should match the S_{WT} values indicated by capillary pressure curves.

- the $\emptyset_E$ models apply the Archie equation only to the $\emptyset_E$ part of the total pore-volume (but nevertheless, normally assume 'clean sand' values for m and n) and add to this a shale-conductivity term using V_{sh} and R_{sh} defined from log readings in adjacent shale beds. Adjustments are normally made - based on local experience - to get S_w = 100% in the water leg and "realistic looking" results in the hydrocarbon-leg. Unfortunately the results cannot be checked/verified against core data, since neither $\emptyset_E$ nor S_{WE} can be measured on cores. Comparison between core and log data can only be made in clean sands where $\emptyset_E = \emptyset_T = \emptyset$ and all saturation equations reduce to the Archie equation.

All considerations above (and in the previous chapters) lead to the conclusion that the $\emptyset_T/Q_v$ models should be preferred to the $\emptyset_E/V_{sh}$ models. This is now accepted by a great majority of the log analyst community (refer to the introductory notes to the V_{sh} and CEC models by Coates and Brown respectively in the "Shaly Sand" reprints Volume of SPWLA).

Of course, ultimately, one also has to make a choice between the two principal $\emptyset_T/Q_v$ models presently in use: the Waxman-Smits model and the Dual Water Model, as well as their derivatives, the normalised W-S and CYBERLOOK evaluation approaches respectively. The forthcoming "SATURATION SEMINAR" will, hopefully, provide good guidance in this.

I, personnally, have a strong preference for the Waxman-Smits model for reasons of its greater simplicity and, in my opinion, better theoretical and experimental basis.

I had to make this statment here because my appreciation of, and favourable experience with the Waxman-Smits model largely determined my appraisal of the merits of the $\emptyset_T/Q_v$ models in this note and in the summaries provided in chapters 9 and 10 below.

9. MERITS AND LIMITATIONS OF THE $Ø_T$ AND $Ø_E$ MODELS (VG12,13)

$Ø_T/Qv$ MODELS

Merits

- scientific/experimental basis
- universal applicabilty
- can be calibrated to core data
- results can be checked against and reconciled with core data
- clay corrections based on parameters from the shaly sands
- can be used with logs alone
- results can be converted to $Ø_E$ system
- facilitates quantitative k assessment via core-log data integration.

Limitations

- productivity and nature of fluids that will flow not easy to assess from $Ø_T$, S_{wt} (but conversion to $Ø_E$ system helps)

$Ø_E/V_{sh}$ MODELS

Merits

- ease of use (logs only)
- qualitative prediction of productivity/fluids perceived to be good

Limitations

- lacking scientific basis
- not universally applicable
- cannot be upgraded/calibrated to cores
- results cannot be checked against/ reconciled with core data
- clay corrections based on parameters from adjacent shale beds

10. THE IDEAL PETROPHYSICAL MODEL(VG 14)

In the light of the foregoing we may now define the ideal model to satisfy the basic requirements for petrophysical input in Petroleum Engineering studies, from single well evaluations to complex reservoir simulators:

- the results should be FULLY COMPATIBLE WITH CORE ANALYSIS DATA; this implies models (for S_w, k estimates) based on the $Ø_T$ SYSTEM
- SATURATION calculations should properly compensate for clay conductivity effects in the sands; this implies $Ø_T/Q_v$ MODELS
- PERMEABILITY ASSESSMENT should be based on both TOTAL AND EFFECTIVE POROSITY CONCEPTS (whereby $Ø_E$ is linked to $Ø_T$ via Q_v and salinity), paying due attention to the distribution of shale in the formation.

APPENDIX

SUGGESTED EVALUATION PROCEDURE USING THE TOTAL POROSITY SYSTEM WITH THE WAXMAN-SMITS MODEL

I CORE ANALYSIS

1. Routine Core Porosity (approximately at 1 ft intervals)

   Ø core (atm) = PV/BV

   - After cleaning, dry sample at 105°C (vacuum oven)
   - BV by caliper/ruler or mercury displacement
   - PV by resaturation or gas expansion (Boyle)

2. Porosity at "in situ" Stress (on selected samples)

   - Measure Ø at steps of increasing effective overburden stress applied to the sample in all-directional (isostatic) mode up to $P_{eff(initial)} = P_{overb} - P_{res(initial)}$.

   - For depletion type reservoirs without pressure support, one may consider using P_{eff} values up to the expected value at abandonment conditions for possible future use.

   - Formation resistivity factor (F) should preferably be measured simultaneously with Ø.

   - Calculation of Øcore (in-situ); assuming uniaxial stress condition in the reservoir and Poisson's ratio (ν) of 0.3:

   $$\varepsilon_z = \frac{1}{3}\left(\frac{1+\nu}{1-\nu}\right)\varepsilon = 0.62\,\varepsilon \qquad \text{(Ref. 20)}$$

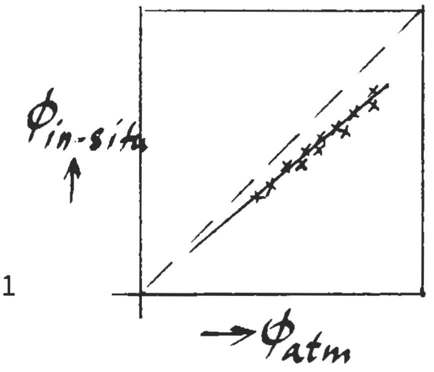
   Therefore

   $$\phi_{\substack{core\,(in\text{-}situ)\\ uniax}} = \frac{1-0.62\,\Delta Vpi/Vpo}{1/\phi_{atm}-0.62\,\Delta Vpi/Vpo} \quad ---(1)$$

   The actual porosity of the sample in the cell (at which also the F value may have been measured) is of course:

   $$\phi_{core(isost)} = \frac{1 - Vpi/Vpo}{1/\phi_{atm} - Vpi/Vpo} \quad -------(2)$$

3. Conversion of routine ϕ_{atm} to $\phi_{in\text{-}situ}$ using the data obtained on selected samples:



- make Y on X free-regresion to get $\phi_{in\text{-}situ} = a\phi_{atm}+b$
- forced regression through (0,0) may also be acceptable (and easier to use): $\phi_{in\text{-}situ} = a\phi_{atm}$

4. <u>Measurement of Qv</u> (on selected samples or end pieces of plugs used for F, I measurements). With titration method giving CEC in meq/100 gr dry sample:

$$Q_{v(atm)} = \frac{(1-\phi_{atm}).\,\rho_g\,.\,CEC}{100\,.\,\phi_{atm}}$$

NB: Also non-destructive techniques can be used to obtain Qv (eg membrane potential technique or conductivity measurements at different salinities).

Conversion to Qv(in-situ)

$$Q_{v(in\text{-}situ)} = Q_{v(atm)} \cdot \frac{\phi_{(atm)}}{\phi_{(in\,situ)}} \cdot \frac{(1-\phi_{in\text{-}situ})}{(1-\phi_{atm})}$$

5. <u>Develop Qv - Ø</u> relation by regression of log Qv in-situ on log $Ø_{in\text{-}situ}$ or, preferably, Qv in-situ on 1/Ø in-situ (linear scales) to yield

$$Q_{v(in\text{-}situ)} = a\,\phi_{in\text{-}situ}^{-b}\ , \text{ or } Q_{v(in\text{-}situ)} = \frac{a}{\phi_{in\text{-}situ}} - b$$

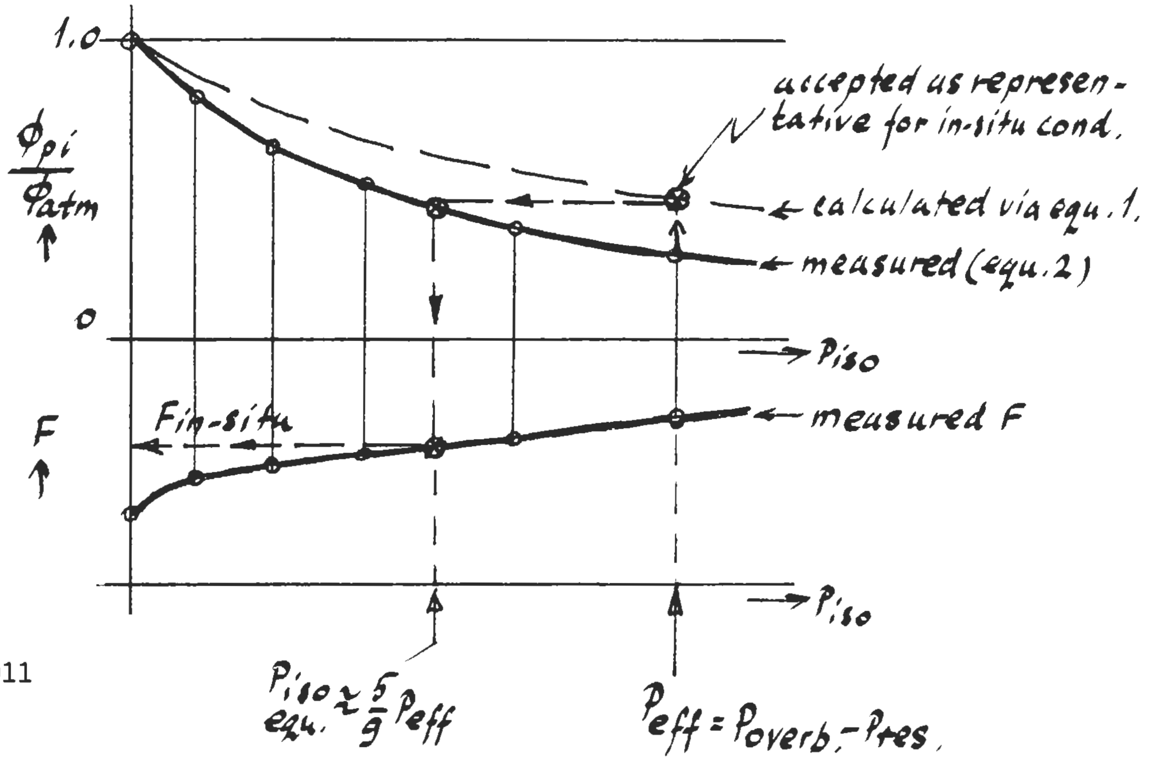
6. <u>Obtain F in-situ - Ø in-situ Data Pairs</u>

<u>Alternative 1</u>

F in-situ = Ro/Rw measured simultaneously with Ø in-situ at Piso ≈ 5/9 Peff (using simulated formation water) or

<u>Alternative 2</u>

Using F in-situ, Ø in-situ results at increasing Piso values one can find the correct F in-situ value corresponding to the in-situ porosity at uniaxial stress condition:



7. Convert F in-situ to F* in-situ

$$F^*_{in-situ} = F_{in-situ}\left(1 + R_W B Q_{V(in-situ)}\right)$$

Use Rw and B at lab conditions.

8. Define a*, m* (F* – Ø relation)

Plot F* in-situ vs Ø in-situ on log-log paper.
Free regression of log F* on log Ø yields

$$F^*_{in-situ} = a^* \phi_{in-situ}^{-m^*}$$

9. Define n*

- Measure I = Rt/Ro at increasing non-wetting phase saturation (preferably at Piso ≈ 5/9 Peff).

- Correct I for shaliness:

$$I^* = \frac{R_t}{R_o} \cdot \frac{(1 + R_W B Q_V / S_{WT})}{(1 + R_W B Q_V)}$$

- B and Rw at lab dconditions.

  Regress log I* on log Sw (forced regression) to yield $I^* = Sw^{-n^*}$

II LOG CALIBRATION AND EVALUATION OF SwT

1. General

The Waxman-Smits equation is (ref. 22, 23):

$$S_{WT} = \left[\frac{R_t(1 + R_W.B.Q_V/S_{WT})}{a^*.\phi_T^{-m^*}.R_W}\right]^{-\frac{1}{n^*}}$$

Note that in clean sand Qv = 0, a* = a, m* = m, n* = n and the above equation reduces to the Archie equation:

$$S_W = (R_t/a.\phi^{-m}.R_W)^{-1/n}$$

The W-S equation can be solved iteratively using

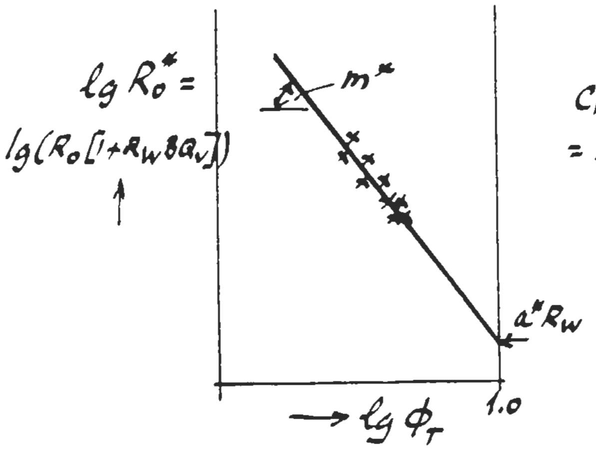
- $Ø_T$ = ØD from the density log calibrated against in-situ core porosity as shown below (or from $\phi_T = \phi_E + V_{sh} \cdot \phi_{Tsh}$ using other logs, or as ØT = 1 – Σv mineral(i), etc)

- a*, m*, n* as already defined by core data

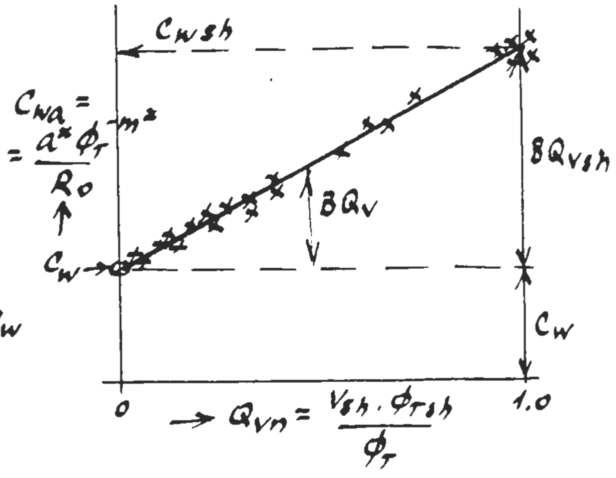
- Rw and B at in situ temp.

- Following plots are useful to verify consistency of parameters:

(a)



(b)

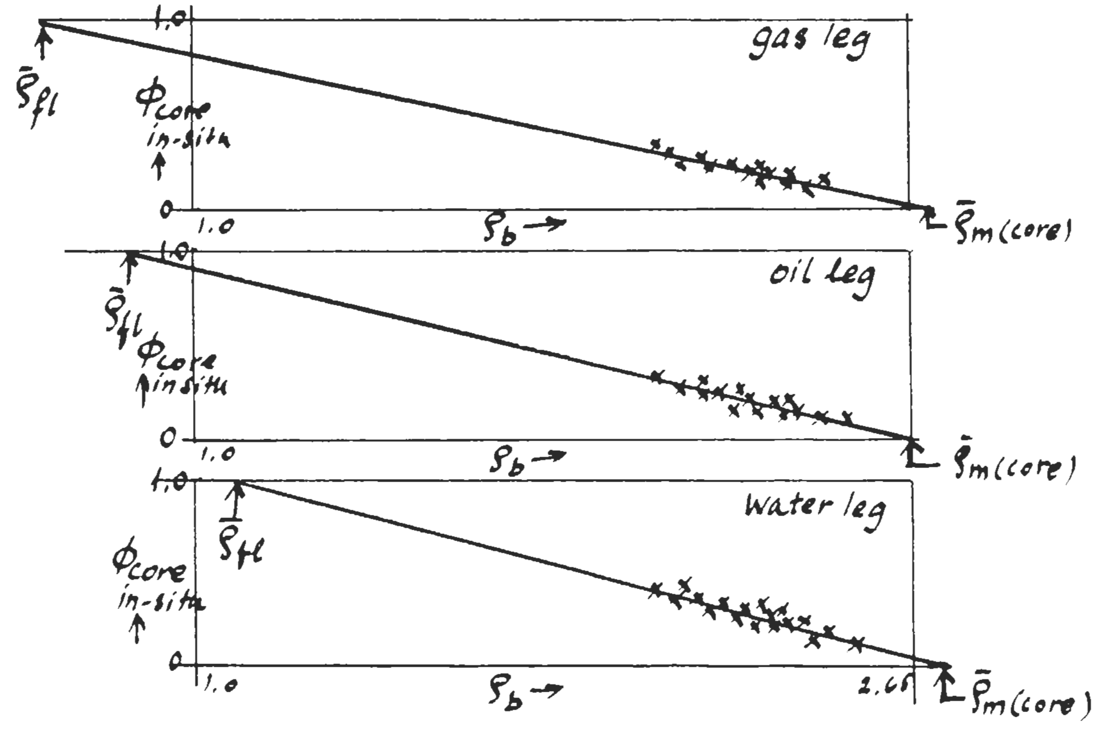


Plot (a) - requires a prior knowledge of Rw to calculate Ro*;
- it provides a check on the internal consistency of $\phi_T = \phi_D = \phi_{core}$, a*, m*, Rw and Qv-ØT relation.

Plot (b) - does not require prior knowledge of Rw;
- it provides Rw (and Rwsh, eg for use with the normalised Qv approach - ref. 10) and facilitates calculation of Qv from log data $(Q_{vsh} = (C_{wsh} - C_w)/B;\ Q_v = Q_{vn} \cdot Q_{vsh})$ for comparison with core data or for solving the W-S equation in the absence of core data.

2. Derivation of $Ø_T$

The first basic step of course is derivation of ØT from logs. This is normally done on the basis of the density log calibrated against Øcore (in-situ) in gas-, oil- and water-leg separately (if both WBM and OBM are used within a field separate correlations are required for these muds). This approach may sound rather simplistic but it is a very pragmatic one (especially if OBM is used) and yields reasonable accuracy.



Free regression of Øin-situ on ρ_b may yield mathematically the most accurate relationship for ØT estimate but can result in unrealistic ρ_m and ρ_f values; this can make it difficult to properly judge the validity of core and log data. Hence, at least as a check, forced regression through ($\rho_{m(core)}$, $\phi = 0$) is recommended. The resulting ρ_f should make sense (according to expected mixture of ρ_{mf} , ρ_w and ρ_{HC}).

If core data indicate variation (usually increase) of ρ_m with decreasing porosity (or with increasing shale content) there are several ways to account for this in the calibration (eg by making ρ_m a function of V_{sh}). The end result from logs ($\phi_{T(logs)}$) should match Øcore(in-situ).

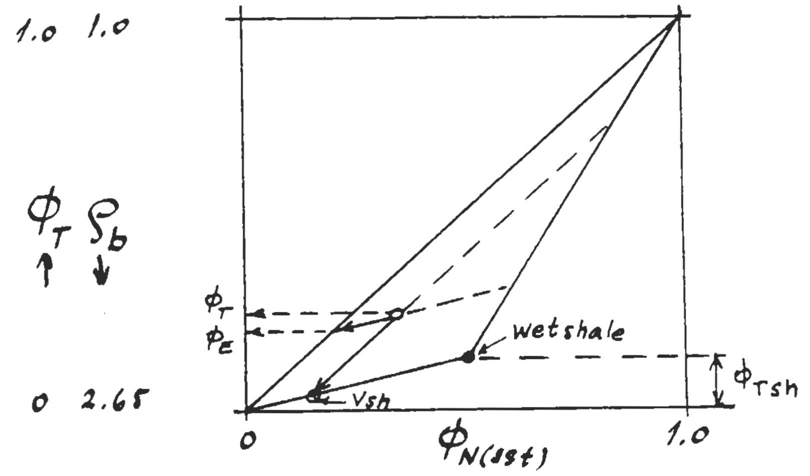
There are of course several other ways to derive ØT from logs, eg

(i) One can use the traditional techniques to derive ØE from the various porosity logs or from the combination of density/neutron and add to this the shale-associated porosity, ie

$$\phi_T = \phi_E + V_{sh} \cdot \phi_{Tsh}$$

Where ϕ_{Tsh} should be assessed on the basis of core-data and density log ($\rho_{m(sh)}$ is often close to $\rho_{m(sand)}$).

Graphical illustration of this approach is as follows:



(ii) Using statistical/probabilistic evaluation packages, the sum of the dry mineral fractions (including $V_{cl(dry)}$) subtracked from unity yields total porosity:

$$\phi_T = 1 - \Sigma V_{mi}$$

3. Corroboration of Results

Whatever method is used, ØT from logs should match Øcore(in-situ) and the Swt values derived from the W-S equation should match the Swt indicated by oil-water or air-brine capillary pressure data. Air-mercury cap curves require corection for clay-bound-water (ref 9) before comparison can be made with Swt(log).

4. Problem of Fine Sand/Shale Laminations

Problems may be encountered in matching core and log derived values if the laminations are beyond the vertical resolution of the logging tools. An approach to reconcile core and log data in such cases is proposed in ref 11.

5. Permeability Estimate

Routine Kair, Øcore data should be calibrated against in-situ brine permeability measurements (using simulated formation water and the appropriate isostatic stress on the sample) and Øcore(in-situ) measurements. If these are not available, an approach suggested in ref. 12 may be applied to derive an in-situ K-Ø relation. Permeability relations can of course be refined by incorporation of permeability related parameters other than Ø and by developing correlations for each individual facies.

III $Ø_T$ - WAXMAN-SMITS APPROACH IN THE ABSENCE OF CORE DATA

Such an approach, based on the concept of normalised Q_v $(Q_{vn} = V_{sh} \cdot \phi_{Tsh} / \phi_T)$ is described in ref. 10.

As shown in fig (b) before, BQv is the slope of the $C_{wa} - Q_{vn}$ plot. This can be zero (practically no clay-effects on Cwa) or positive, but never negative. Wrong (too low) choice of m* or wrong (too high) $Ø_T$ values (eg by using $Ø_T$ = (ØN+ØD)/2 which is not $Ø_T$) can lead to a negative slope and hence negative Qv.

On the other hand, unrealistically high slope (and hence Qv) may result due to too high m^* and/or too low $Ø_{Tsh}$ values; adjustment of these parameters should resolve this problem.

I hope that the very sketchy notes provided above will be of some help to those not very familiar with the W-S-type evaluation.

I.J.

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VG1

POROSITY SYSTEMS & PETROPHYSICAL MODELS

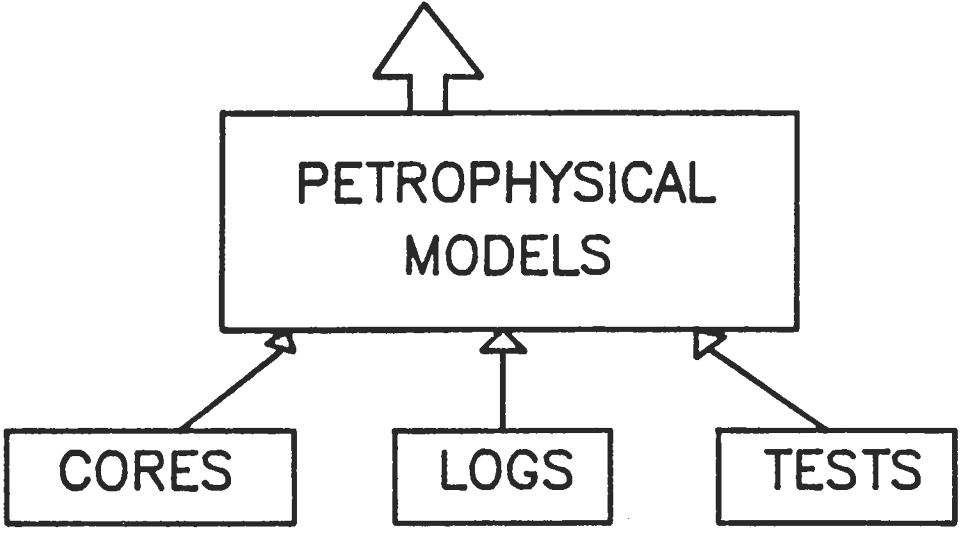
- EVALUATION REQUIREMENTS
- POROSITY CONCEPTS (ϕ_T, ϕ_E)
- POROSITY FROM CORES & LOGS
- MODELS FOR $S_W - \phi - K$
- MERITS & LIMITATIONS OF ϕ_T & ϕ_E SYSTEMS
- THE IDEAL PETROPHYSICAL MODEL

EVALUATION REQUIREMENTS

- HYDROCARBON IN PLACE
- PRODUCTIVITY

$$HIP = A.H.\left\{\frac{N}{G}\right\} \phi \; (1-S_W)$$

- ϕ ---- storage capacity
- $S_W = f(\phi$, m, n, --- etc.)
- $N/G = f(k \rightarrow \phi$, --- etc.)
- PRODUCTIVITY $= f(k \rightarrow \phi$, --- etc.)


PETROPHYSICAL MODELS

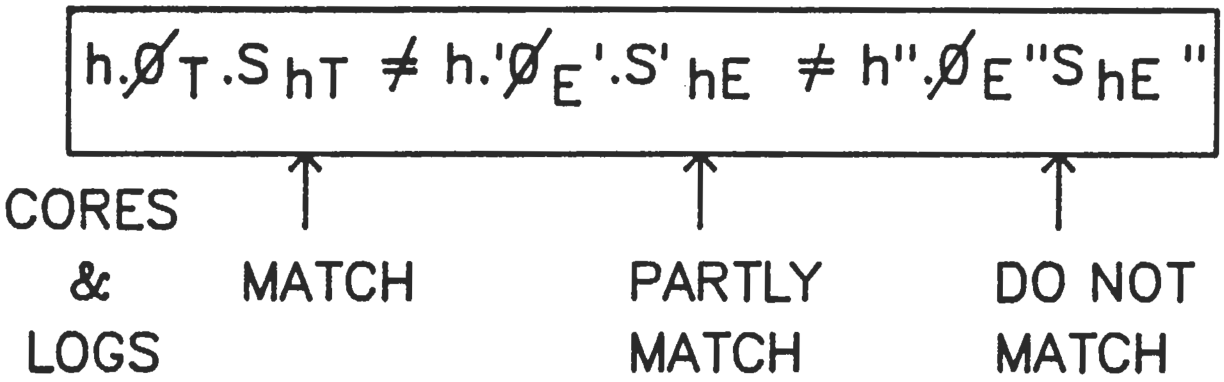
CORES

LOGS

TESTS

PROBLEM

- DIFFERENT Ø DEFINITIONS YIELD DIFFERENT RESULTS



$$h . \phi_T . S_{hT} \neq h .' \phi_E ' . S'_{hE} \neq h'' . \phi_E '' S_{hE} ''$$

CORES
&
LOGS

MATCH

PARTLY MATCH

DO NOT MATCH

WHICH ONE DO WE BELIEVE?

VG4

POROSITY CONCEPTS

1. TRADITIONAL TOTAL POROSITY

ϕ_T --- INCL. ALL FLUIDS

2. TRADITIONAL EFFECTIVE POROSITY

$$\phi_E = \phi_T - V_{sh} \cdot \phi_{Tsh}$$

(EXCL. SHALE WATER)

3. Q_V – RELATED EFFECTIVE POROSITY

$$\phi_E = \phi_T - V_{cl} \cdot \phi_{Tcl}\,(Qv)$$

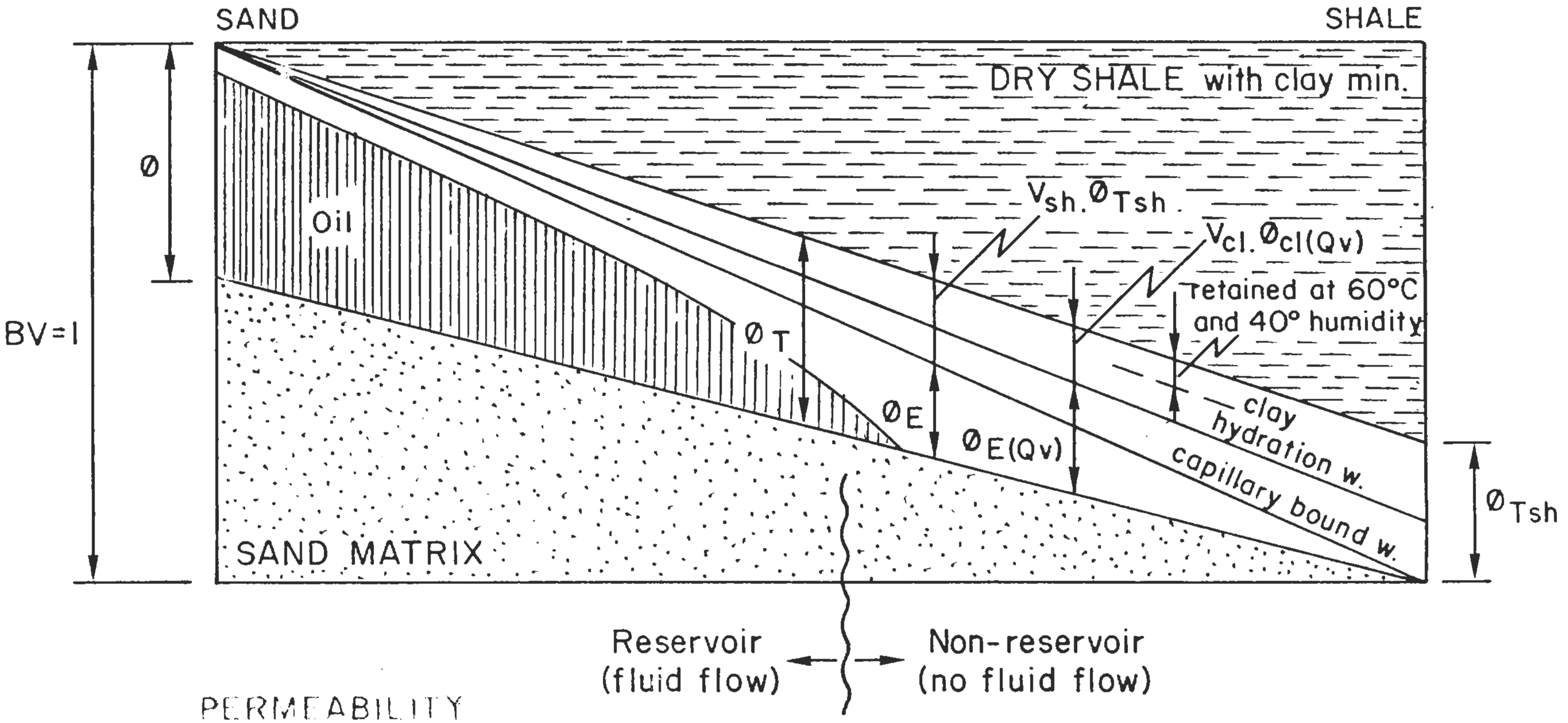
(EXCL. CBW)

$\downarrow$

(i) $\phi(HSK) = \phi_T(1-0.64S^{-0.5}+0.22)Q_V$

(ii) $\phi(CCD) = \phi_T(1-\alpha V_Q^H\,Q_V)$

POROSITY CONCEPTS - S_W MODELS



PERMEABILITY

SATURATION

Archie

$$\boxed{\frac{1}{R_t} = \frac{Ø^m . S_W^n}{R_W}}$$

$\phi_E | V_{sh}$ MODELS → eg.

$$\boxed{\frac{1}{R_t} = \frac{Ø_E^m . S_{WE}^n}{R_W} + \frac{V_{sh} . S_{WE}}{R_{sh}}}$$

ϕ_T / Q_V MODELS → eg.

$$\boxed{\frac{1}{R_t} = \frac{Ø_T^{m*} . S_{W_T}^{n*}}{R_{we}}} \longrightarrow R_{we} = f(sal., Q_v, t)$$

POROSITY FROM CORES

$$\phi = \frac{PV}{BV}$$

PV — RESATURATION OR GAS EXPANSION

BV — CALIPER/RULER OR MERCURY DISPL.

DRYING METHODS

- 105 °C (VACUUM) $\longrightarrow \phi_{CORE} \approx \phi_T$
- 60 °C (40 ° HUMID) $\longrightarrow \phi_E < \phi_{CORE} < \phi_T$

REMARKS

1. INSUFFICIENT DRYING RESULTS IN
   - too low ϕ, ϱg, K_{air}, m, n, cap. curve S_w
   - too high Q_v

2. ϕ_E cannot be measured directly on cores

POROSITY FROM LOGS

ϕ_T

$$\phi_T = \underset{\text{IN-SITU}}{\phi_{CORE}} = \phi_D = \frac{\rho_m - \rho_f}{\rho_m - \rho_f}$$

$$\phi_T = 1 - \Sigma V_{min(i)}$$

$$\phi_T = \phi_E + V_{Sh} \cdot \phi_{Tsh}$$

REMARKS

(i) $\phi_N > \phi_T$

DUE EFFECT $HI_{cl(dry)}$

(ii) $\frac{\phi_N + \phi_D}{2} \neq \phi_T$

(iii) ϕ_{SL} AFFECTED BY SHALE DISTRIBUTION & COMPACTION

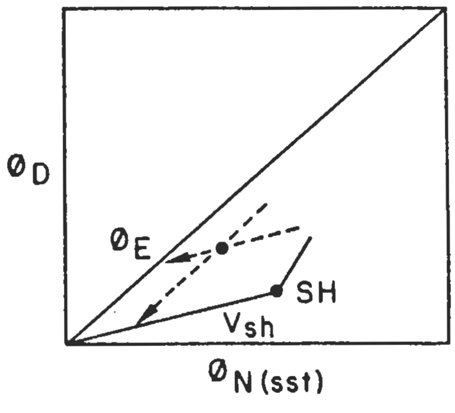
$\phi_E = \phi_T - V_{Sh} \cdot \phi_{Tsh}$

$$\phi_E = \phi_D - V_{Sh} \cdot \phi_{Dsh}$$

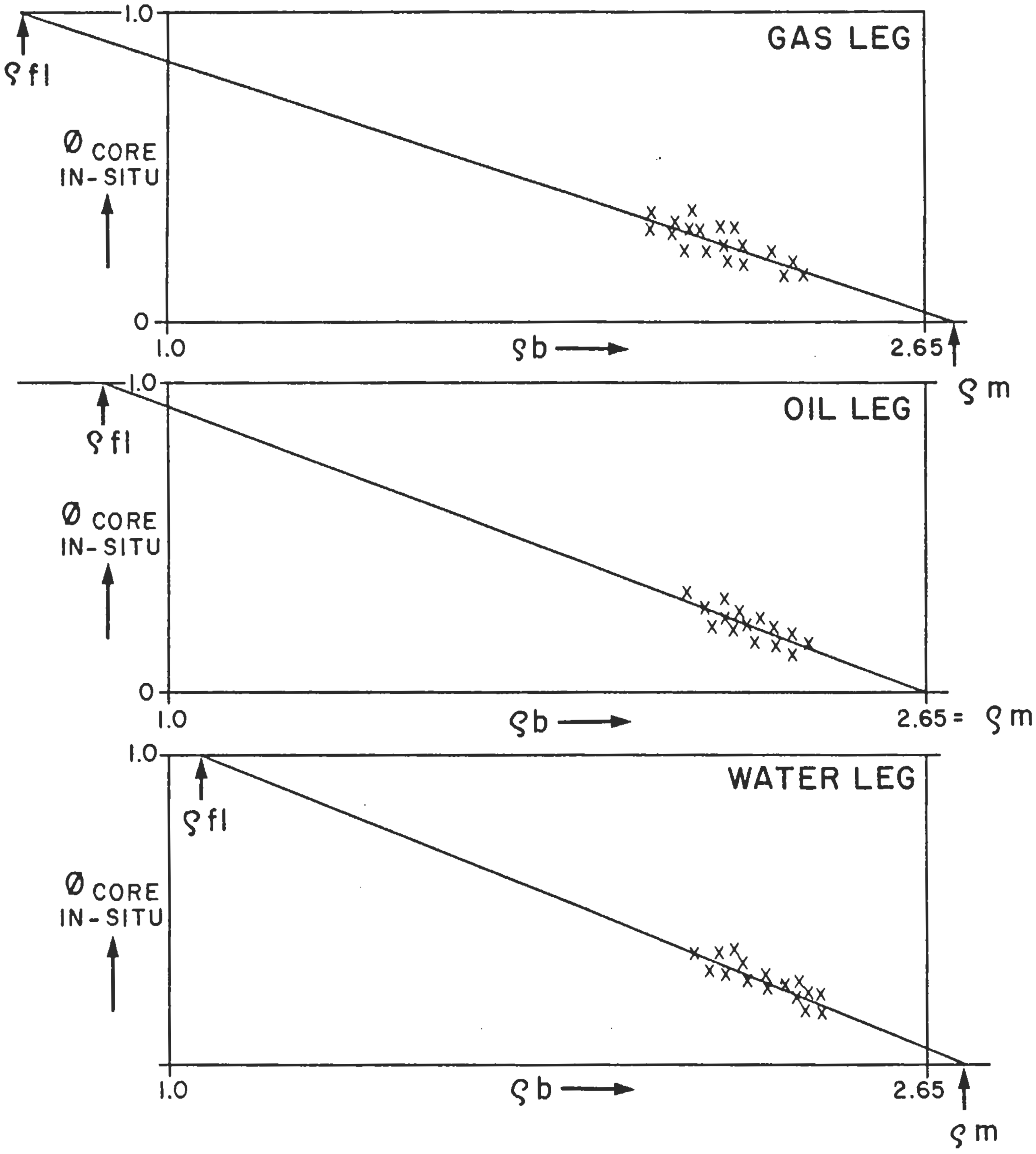
$$= \phi_N - V_{Sh} \cdot \phi_{Nsh}$$

$$= \phi_{SL} - V_{Sh} \cdot \phi_{SL(Sh)}$$

ALSO FROM COMBINATION OF LOGS, E.G.



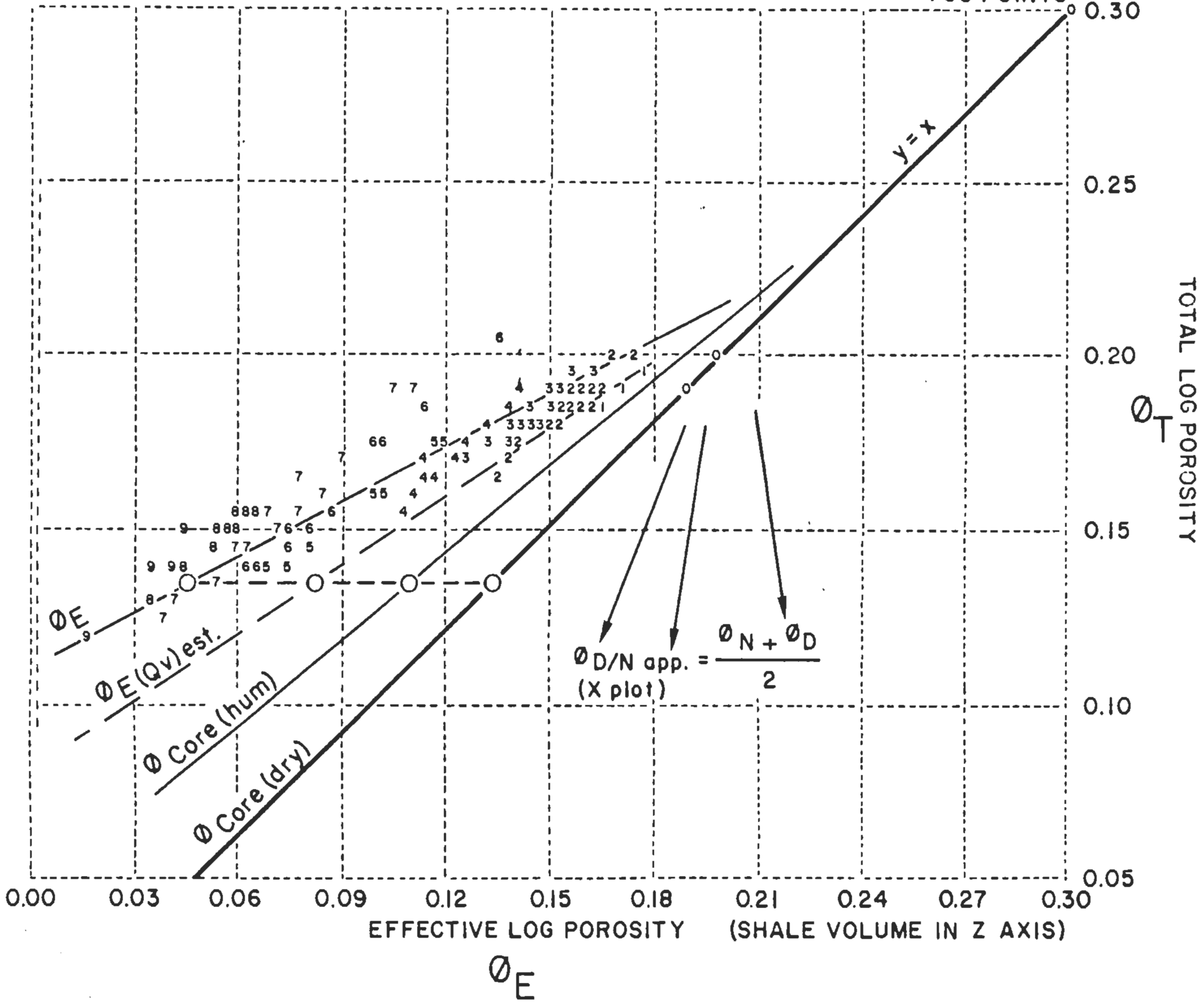
CALIBRATION OF DENSITY LOG



PROPERTIES OF CLAY MINERALS

CLAY MINERAL	$HI_{cl(dry)}$ (fraction)	ϱ_m (g/cm^3)	CEC ($\frac{meq}{g}$)
MONTMORILLONITE	0.13	2.2(?)–2.7	0.8–1.6
ILLITE	0.12	2.64–2.69	0.2–0.3
CHLORITE	0.34	2.6–2.9	0.05–0.35
KAOLINITE	0.36	ca.2.61	0.02–0.08

COMPARISON OF CORE- AND LOG- DERIVED POROSITY



COMPARISON OF CORE POROSITIES ($\emptyset$DRY AND $\emptyset$HUM) WITH LOGAN $\emptyset_E$
(after Heslop - ref. 7)

SATURATION MODELS

ARCHIE

CLEAN S.

$$\boxed{\frac{1}{R_t} = \frac{\phi^m \, . \, S_w^n}{R_w}}$$

SHALY S.

ϕ_T / Q_V MODELS

E.G. WAXMAN & SMITS

$$\boxed{\frac{1}{R_t} = \frac{\phi_T^{m*} \; S_{WT}^{n*}}{R_{we}}}$$

ALSO
- ARCHIE (high sal., low ϕ_{Sh})
- NORMALISED W&S
- DUAL WATER
- CYBERLOOK
- CLASS

ϕ_E / V_{Sh} MODELS

E.G. MODIF. SIMANDOUX

$$\boxed{\frac{1}{R_t} = \frac{\phi_E^m \, S_{WE}^n}{R_w} + \frac{V_{Sh} \; S_{WE}}{R_{Sh}}}$$

ALSO
- LAMIN. SHALE
- TOTAL SHALE
- INDONESIA
- NIGERIA
- ARCHIE WITH "meff"

ϕ_T / Q_V MODELS

MERITS

- SCIENTIFIC/EXPERIMENTAL BASIS
- UNIVERSAL APPLICABILITY
- CAN BE USED WITH LOGS ALONE
- CAN BE CALIBRATED TO CORES
- RESULTS CAN BE INTEGRATED & RECONCILED WITH CORE DATA
- CLAY CORRECTIONS BASED ON PARAMS FROM THE SANDS

LIMITATIONS

- PRODUCTIVITY PREDICTION WITH ϕ_T, S_{WT} CAN BE POOR (CONVERSION TO ϕ_E, S_{WE} HELPS)

ϕ_E / V_{Sh} MODELS

MERITS

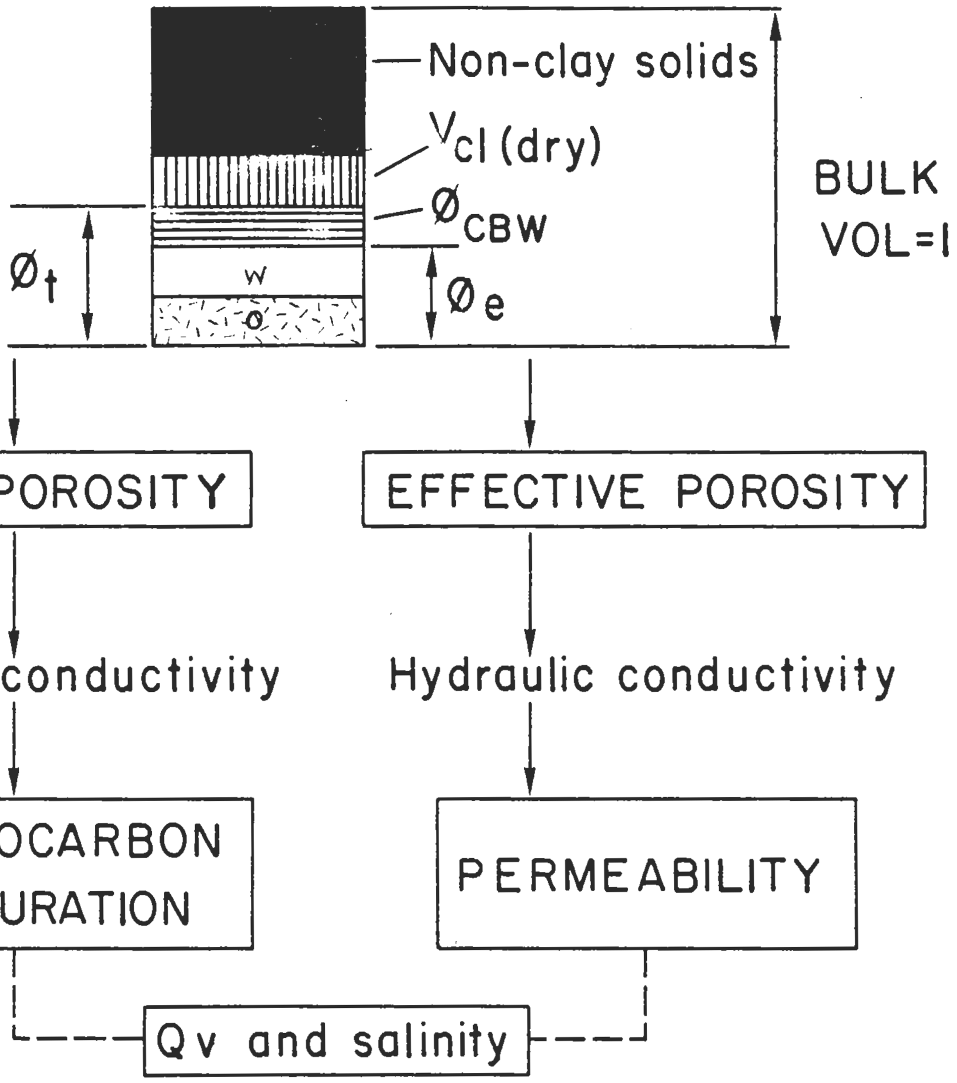
- EASE OF USE (LOGS ONLY)
- PRODUCTIVITY PREDICTION PERCEIVED GOOD

LIMITATIONS

- LACKS A SOUND SCIENTIFIC BASIS
- NO UNIVERSAL APPLICABILITY
- CANNOT CALIBRATE TO CORES
- RESULTS CANNOT BE INTEGRATED WITH CORE DATA
- CLAY CORRECTIONS BASED ON ADJACENT SHALE BEDS

THE IDEAL MODEL

- FULL CORE/LOG DATA INTEGRATION
- USE OF BOTH THE ϕ_T & ϕ_E CONCEPTS
  LINKED VIA Q_V AND SALINITY



TOTAL POROSITY

Electrical conductivity

HYDROCARBON SATURATION

EFFECTIVE POROSITY

Hydraulic conductivity

PERMEABILITY

Qv and salinity