

DETERMINATION OF INITIAL FLUID SATURATIONS USING TRACED DRILLING MEDIA

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ABSTRACT

Initial saturations of hydrocarbons and water, that exist in porous media, control reserves in place and, in many cases, the deliverability/recovery of these reserves. Hence, their accurate determination is essential for proper economic and reservoir engineering evaluation and optimization.

Electric logging techniques are commonly used to estimate initial fluid saturations, but may suffer from problems with accurate determination of the log calibration constants for a given reservoir rock, as well as the accurate determination of in-situ water resistivity in some situations. Advanced logging techniques, such as magnetic resonance, have been used in recent years to estimate the saturation of bound and free water. The use of these techniques is increasing, but cost and other factors have limited their widespread usage. Various types of reactive tracers and other in-situ techniques for the determination of initial fluid saturations have also been used to attempt to determine initial fluid saturations with varying degrees of success.

Another family of techniques, on which this paper concentrates, is the actual measurement of in-situ initial or swept zone fluid saturations on samples of appropriately obtained, preserved, handled and analyzed core material. Different coring techniques and fluid and coring procedures will be discussed, along with the relative merits and advantages/disadvantages of each. Illustration of the results of various techniques will be given with respect to their cost, effectiveness and accuracy of the data generated.

INTRODUCTION

Initial fluid saturations, defined as the fraction of the interstitial space in a pore system occupied by oil, water and gas, are key factors in the determination of initial reserves of actual and recoverable hydrocarbons in place and dominate reservoir flow properties due to the strong influence they exhibit on relative permeability⁽¹⁻⁵⁾. Surprisingly, in many reservoirs, initial fluid saturations are virtually unknown or improperly measured, resulting in gross over or under estimation of oil or gas reserves in place. The improper determination of these initial saturations may also greatly

affect the potential for formation damage due to phase trapping, resulting in a poor appraisal of deliverability. In some cases, improper initial saturation estimates can lead to the bypassing of potentially productive pay zones, resulting in significant lost reserves or the erroneous completion of ineffective pay and wet or no production from the completed zone.

WHY IS IT IMPORTANT TO HAVE A PROPER KNOWLEDGE OF INITIAL FLUID SATURATIONS

Improper determination of the initial oil, water or gas saturations existing in porous media may often lead to expensive mistakes in the development of a field. In some cases, large amounts of capital are invested where minimal reserves are present or marginal flow is obtained. In other cases, viable pay is overlooked due to a perceived belief, from improper saturation evaluations, that the pay will be wet or non-productive. The hazards involved with an inadequate understanding of initial saturation conditions can generally be grouped into three categories:

Poor Initial Reserves Evaluation. Oil or gas in place is based on a simple volumetric calculation of hydrocarbon volume present in the effective porosity of the system. Since this value is usually assumed to be $1-S_{wi}$, it can be seen that over or under estimation of the initial water saturation can grossly affect the perceived amount of oil or gas in place in the reservoir. An under estimation of S_{wi} could result in costly development of a field which has less oil or gas in place than anticipated, resulting in limited or negative return on ultimate investment. Conversely, if S_{wi} is over estimated, a potentially viable and lucrative pay zone may be abandoned.

Many low permeability gas reservoirs exist in conditions of "subirreducible" initial water saturation^{6,7,8}. If relatively little fluid invasion has occurred during the drilling and completion process, this can often be detected by significant separation between the shallow and deep induction logs and extremely high resistivities in the deep, uninvaded portion of the formation (sometimes in the hundreds or thousands of ohms). Due to the adverse capillary nature of these very low permeability systems, they tend to both spontaneously imbibe and permanently retain invaded water based filtrate in what is known as an "aqueous phase trap" or "water block"⁸. The basic mechanism of a phase trap in a low permeability gas reservoir of this type is illustrated in Figure 1. If deep

invasion occurs, this can result in the creation of a zone of extremely high water saturation about the wellbore which may be misinterpreted as wet. Some tight gas sands that are subirreducibly saturated may exhibit trapped saturations of 70% or greater, when the initial saturation may actually be quite low (perhaps 10-15%). This is pictorially illustrated as Figure 2. Both the reserves and the productive potential may be grossly underestimated. In many cases of this type, the subirreducibly saturated initial condition is the only factor that allows these low permeability formations to be viable economic gas producing targets. If the formations were at their "normal" irreducible water saturation for the capillary geometry under consideration, initial water saturations would be so high that gas in place and the ability of the formation to transmit that gas to the wellbore (due to adverse initial relative permeability effects) would be reduced to the point that the zone would no longer be an economic candidate for completion.

Saturation measurements may also be used to determine the target oil in place for secondary or tertiary EOR projects. Often coring techniques are used to evaluate residual oil saturations in a zone previously swept by water or gas to ascertain if sufficient mobile oil remains in place to warrant the implementation of a costly enhanced oil recovery process, such as miscible or near miscible gas injection or chemical flooding.

Poor Completion Zone Selection. Figure 3 illustrates a typical set of water-oil or gas-water relative permeability curves. It can be seen that underestimation of the initial water saturation may result in completion of zones with high potential water phase relative permeability which will result in immediate high water cuts and poor oil or gas production rates (i.e. the water saturation was believed to be at point "A", when, in fact, it is actually at point "B" on Figure 3). Conversely, over estimation of initial water saturation may result in the decision to not complete a zone which could conceivably produce at economic rates, resulting in lost opportunities and revenue (i.e. the water saturation was thought to be at point "B" on Figure 3 in this case when it was actually at point "A").

Flow Mechanics. Multiphase flow is governed by the relative permeability which exists between the individual phases. Relative permeability is, in turn, governed directly by the respective saturations of the individual fluid phases

present in the porous media. Proper knowledge of both the relative permeability characteristics of the porous media (which are determined by appropriate experimental tests in the laboratory) and the initial saturation conditions will allow inflow calculations to determine if, in the presence of mobile or immobile water or gas saturations, economic production rates of oil or gas will be feasible.

SATURATION DETERMINATION TECHNIQUES

Initial saturations are commonly determined using the following techniques:

- Log based saturation evaluations
- Direct saturation measurements on in-situ samples

This discussion will centre about the proper techniques to obtain representative saturation data using direct saturation measurements on core samples.

OBTAINING CORE MATERIAL FOR SATURATION ANALYSIS

In most situations, the objective is to obtain the initial water saturation which exists in the porous media. In some cases, where three phases (oil, water and gas) are thought to be present, accurate determination of the initial oil saturation is also required. Typical coring operations, particularly in higher permeability porous media, can result in significant flushing of the obtained core material by the pressure and jetting action of the coring fluid at the bit. If the coring fluid is water based, this will obviously result in an undesirable increase in the measured water saturation. If the coring fluid is oil based, the initial water saturation will be unaltered if it is at a subirreducible or irreducible value (i.e., immobile). If the water saturation is mobile (such as in a transition zone or aquifer zone), oil-based mud filtrate may flush the core and reduce the obtained water saturation. Oil-based coring fluids, therefore, usually provide a good estimate of the "irreducible", but not necessarily, the initial water saturation which exists in a reservoir. Invert emulsion muds and oil-based muds containing high oil-wetting surfactant concentrations may alter the wettability in the flushed portion of the core which may also reduce the apparent measured water saturations.

Gas has also been used as a coring fluid. Due to the poor heat transfer capacity of gas, a large amount of heat is generated during the coring process. This heat, combined

with the dehydrated nature and high rate of gas circulation required to clean the hole, often results in desiccation of the core and artificially low water saturations.

PROPER SELECTION OF CORING FLUID

Selection of the proper type of coring fluid is essential for obtaining quality core that can subsequently be used for saturation and special core analysis measurements. The type of coring fluid used and the degree of invasion will greatly influence accuracy of results. The specific parameters we want to measure will determine the optimum coring fluid for use in a given situation. **Table 1** summarizes the advantages and disadvantages of various types of coring fluids with respect to in-situ saturation determination.

PROBLEMS ASSOCIATED WITH ATTEMPTING TO MEASURE FLUID SATURATIONS ON CORE MATERIAL

Attempting to infer accurate in-situ saturations from core material can be fraught with problems, and the accuracy of the results may be seriously compromised if the core is not drilled, handled, preserved and analysed in the proper fashion. Problems that commonly affect the accuracy of saturation measurements obtained from core analysis techniques include:

1. Flushing of the core material and alteration of the initial saturations caused by the invasion of extraneous fluids (discussed in the preceding section).
2. Expulsion of fluids from the core material as the core is tripped to surface and pressurized fluids expand and are pushed from the pore space of the core.
3. Shrinkage of the in-situ fluids associated with gas evolution and thermal contraction.
4. Inaccuracies in the analytical techniques used to determine the initial saturations on a laboratory basis.

Expulsion and Fluid Losses. For core samples containing fluids at saturation levels above the critical mobile value, fluids may be lost from the core as the core is pulled to surface and pressurized gas (contained either as a free phase in the pore system or as a solubilized phase in liquid

hydrocarbons) evolves and displaces either mobile oil or water from the pore system. Two techniques are usually used in this situation - pressure coring and sponge coring. Pressure coring eliminates the expulsion of fluids from the core by maintaining the reservoir pressure until the samples and the fluids contained therein can be subjected to cryogenic freezing. Sponge coring is designed to "capture" any expelled fluids in the surrounding sponge material which can then be subsequently analysed, the volume of the expelled fluids determined and these saturations then instituted back into the pore volume of the adjacent full diameter core sample. For other techniques, estimates of the volume and type of fluid expelled from the core during depressurization must be made which will affect the accuracy of the obtained saturation results.

Shrinkage of InSitu Fluids. Saturations on core samples are generally determined using a Soxhlet or Dean Stark extraction apparatus where hot solvent (generally pure toluene) is used to remove both the water (by high temperature vaporization) and hydrocarbons (by miscible extraction) from the core samples. The oil volume obtained from these saturation evaluations is often determined by mass difference of the sample, whereas the water volume removed is measured directly. This means that the oil volume must be corrected for density effects. In many situations, the oil density is assumed to be 1.000 g/cc, which often results in a significant underestimation of the oil volume in place, particularly for reservoirs containing higher API gravity oils.

Most liquid hydrocarbons contain dissolved solution gas at bottomhole temperature and pressure conditions. The dissolution of the gas in the oil causes an expansion of its volume, normally referred to as "swelling". When the core material is brought to surface, in addition to the oil which may be expelled by gas expansion and released from the pore system, the remaining residual oil saturation will also contract in size due to the evolution of gas from the oil (as the saturation analysis is always conducted on a core sample at ambient pressure conditions). Thermal contraction of the oil and water which may be present in the pore system as the core material cools from reservoir temperature may also be significant. These issues are of particular import of deep, hot high pressure and temperature formations where thermal and solubility corrections to the remaining residual fluid volumes may be very substantial. An illustration of this is given in Table 2.

ATTEMPTING TO BACK OUT THE EFFECTS OF CORE FLUSHING - TRACED CORING FLUIDS

Some possibility of invasion, particularly in zones of high permeability, exist even when low invasion coring is used. For this reason, the saturations evaluated from a low invasion coring process may still be in question. This can be remedied in some cases by the use of some type of tracer in the coring fluid. The tracer usually consists of some readily analytical material which is not present (or is present in a low and known concentration) in the naturally occurring formation fluids. If the tracer is present in the fluids removed from the core samples, it can be ascertained that invasion has occurred. If flushing is not complete, the concentration of the tracer in the central section of the core can be used to back out the degree of invasion and hence calculate the true saturation of a given phase which initially existed in the porous media.

The tracer is generally some element which is easily detectable in low concentrations and not naturally present in the formation water. Baseline samples of drilling fluid are taken from the circulating drilling fluid stream regularly during the coring process to obtain a "reference" value of the tracer as a function of depth. This is due to the fact that tracer concentration can vary due to dilution with formation fluids or additions of fluid to the mud system to account for uphole losses to the formation.

Two classifications of tracers are normally used - chemically based tracers and radioactive tracers. Tracers can be used in both oil based and water based systems (although water based tracer systems tend to be much more common).

Chemically Based Tracers. For an aqueous based fluid, these include materials not normally present in the formation water such as various alcohols and soluble ions (i.e. bromides, iodides or nitrates). Oil based tracers would include such materials as iododecane and hexadecane. Chemical tracers are generally inexpensive and easy to analyse, but their deficiency centres about the fact that many water soluble chemical tracers will complex with in-situ formation clays or biodegrade, which permanently consumes all or a portion of the tracer and affects the accuracy of the analysis. In addition, for an accurate analysis for ionic type chemical tracers, a sufficient volume of water or oil must be

removed from the core to obtain an accurate analysis of the tracer. The fluids must be removed by a direct reduction technique such as centrifuging or gas displacement, as high temperature extraction (the normal method for cleaning most cores and removing oil and water) will result in the volatilization of the water from the system, but water soluble ionic tracers will remain in the sample and not be detected. Partial volatilization and capture of the oil or alcohol based tracers are also problematic in this type of analysis. Commutation of the core, after such a process and analysis of the precipitated salts have been used in some situations, but has not tended to be a highly accurate technique. Soluble alcohols will be removed by extraction, but condensation is often incomplete and inaccuracies are often present due to a loss of the volatile tracer from the core due to evaporation between the time the core is removed from the core barrel and when analysis actually occurs.

Isotopic Tracers. Commonly include isotopic forms of water (deuterium and tritium). For oil based systems, tritiated hexadecane is often used. Deuterium (or heavy water as it is sometimes referred to) is inert and easy to use. Since it is an isotopic form of water, it is removed from the core during a conventional extraction process and is not subject to many of the adsorption, retention and removal problems associated with chemically based tracers. Disadvantages of deuterium include its expense (approximately \$1000 per litre) and up to 20 litres may be required to trace a typical mud system to a concentration of 250-350 ppm. This normally results in mud systems being traced in fairly low concentrations, which decreases the detection limit sensitivity. Deuterium is also a stable natural isotope of water and exists in most formation waters in a concentration of 120-150 ppm. This natural pre-existing concentration is not an issue if produced water samples from the field are available to allow an accurate baseline determination. If samples of actual connate water (not fresh water of condensation from the gas) are unavailable (such as the case in many low initial water saturation formations), accuracy of the method may be degraded for low levels of invasion due to uncertainty as to the baseline concentration of pre-existing deuterium in the natural formation water.

Tritium is the preferred tracer for in-situ water saturation determination for most reservoir applications from both a cost and technical viewpoint. Tritium is less expensive than deuterium (a typical mud system can be treated generally for

about one-tenth of the cost), is analysable in concentrations of down to 1 pCi/ml (pCi/ml) (in comparison to the doping concentration of 5000-10000 pCi/ml) and does not naturally exist in formation waters in any significant concentration, so that the need to have a sample of in-situ water for a baseline analysis is negated. Tritium analysis is also quick, less problematic and less expensive in comparison to deuterium analysis. Tritium is a beta emitter, with a half life of 12.3 years and concerns are often expressed about the safety of its use. Most national drinking water standards for tritium are 1000 pCi/ml and typical disposal standard is 1,000,000 pCi/ml, so one can see that the concentration in which mud systems are normally doped generally represents no hazard to humans or the environment. An atomic energy permit, however, is required to handle the concentrated tritium that is used to trace the initial mud system at site, and this process should only be conducted by experienced personnel who will conduct the appropriate site monitoring to ensure that no contamination with concentrated tritium has occurred.

Tritiated oil based fluids can be used in a similar fashion to determine the degree of flushing which has occurred in the oil phase of the core. The effluent in the Dean Stark analysis (the mixture of toluene and extracted oil) is analysed in this situation with a compensating dilution factor to account for the presence of the toluene solvent used to remove the oil from the core being taken into consideration in the evaluation. Tritiated oil based fluids are also useful from the prospective of limited inflow MDT or RFT tests, as the degree of contamination of the obtained bottomhole oil samples with oil based invaded mud filtrate can be easily ascertained as a quick check on overall sample quality.

PROPER PROTOCOL FOR A TRACED SYSTEM TO EVALUATE INITIAL FLUID SATURATIONS

Different applications and equipment should be used depending on the information required for the program. Recommended systems and protocol for traced fluids in certain situations are summarized in **Table 3**.

Figure 4 illustrates how core is sectioned on site to determine a tracer invasion profile. In some cases, where only the initial water saturation is desired and the degree of flushing of the exterior of the core is inconsequential, only the central section of the core is analysed for tracer content

to reduce costs and time. If an evaluation of the degree of flushing is required all three sections may be evaluated. Liquid nitrogen is generally used either onsite or immediately upon receipt of the core material at the analysis lab to cut the plugs to fix saturations in place and avoid the introduction of any other extraneous oil or water based fluids into the core. The cutting process should be conducted as soon as possible to avoid the imbibition of drilling mud into the core which will occur if static exposure over an extended period of time occurs if the core sits immersed in mud in the core barrel. If the samples cannot be cut on site, they should be removed from the core sleeves (and active contact with the traced drilling fluid in the annular space of the core sleeve which may continue to imbibe into the core material), and be preserved to prevent fluid losses and oxidation using PROTEC™ core type polypropylene-aluminum laminate. If the coring job is conducted in a remote location where considerable time or rough handling may be required to bring the material back to the analytical lab, CORESEAL™ type heat strippable plastics (generation "C" class or better) may be better candidates for core preservation material. Although the heat strippable plastics are not as good barriers at preventing osmotic fluid losses as the PROTEC™ type pouches, they are considerably more durable and resistant to puncturing during rough handling which can destroy the integrity of the PROTEC™ pouch and the effectiveness of the resulting seal and preservation. Techniques such as tin foil, plastic type wraps or paraffin coating have very poor mechanical and osmotic stability and should not be considered for any type of medium to long- term core preservation or transport.

The proper technique when cutting the plugs for testing with liquid nitrogen is also important and the samples should be cut in a dry environment. The condensation of water on the surface of the frozen core after cutting can totally disrupt the accuracy of the saturation and tracer measurements, particularly on the small outer section end cuts where surface volume of condensation is large compared to actual pore volume of the samples. This can result in an abnormal situation where the degree of flushing and concentration of tracer observed on the outer sections of the core is less than in the inner core, which is obviously non-physical. **Figure 5** provides an example of invasion down the length of typical core. Spikes in invasion are usually associated with either high permeability streaks, vugs or natural fractures, surges in pump pressure during coring, static rotation or cessation of

drilling in a single spot, or at breaks between individual core barrel trips, where long-term static exposure of mud floods into the top section of the next core to be taken once coring resumes.

Figure 6 illustrates the tritium invasion profile from a typical traced core. **Table 4** provides a summary of typical corrected and uncorrected water saturation measurements for a tritium based coring program.

CONCLUSIONS

1. Determination of correct initial fluid saturations is essential from a reserve evaluation, flow mechanics and reservoir optimization viewpoint.
2. Conventional log analysis type techniques may result in considerable error in the estimation of initial fluid saturations.
3. A variety of core analysis techniques may be used in certain situations to obtain actual measurements of in-situ fluid saturations, but problems can be associated with the improper design and use of these techniques.
4. Choice of the proper coring equipment, coring fluid, preservation, handling and analytical techniques is essential in order to obtain representative saturation data from core material.

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Table 1. Effects of Various Coring Fluids on Insitu Saturations

Fluid Type	Advantages	Disadvantages
Water-based Mud	Good for immobile S_o	-May reduce mobile S_o -May reduce mobile S_g -May increase S_w
Pure Oil Mud	Good for immobile S_{wi}	-May increase S_o -May reduce mobile S_w -May reduce mobile S_g -May reduce immobile S_g (solubility effects)
Pure Gas	Good for immobile S_o	-May reduce mobile S_o -May reduce mobile S_w -May reduce immobile S_w (desiccation)
Invert Emulsion Mud	Not recommended	-May reduce mobile S_w -May reduce immobile S_w (wettability alterations) -May reduce mobile S_g -May reduce immobile S_g (solubility effects) -May increase S_o

Table 2. Correction of Saturations for Density, Swelling and Thermal Expansion - Reservoir

Measured			Corrected		
S_o	S_w	S_g	S_o	S_w	S_g
0.273	0.241	0.486	0.592	0.268	0.131
0.253	0.316	0.431	0.548	0.352	0.083
0.284	0.248	0.468	0.615	0.277	0.075

$T = 146.2^\circ\text{C}$

$\hat{\alpha}_o = 1.72$

$\hat{\alpha}_w = 1.115$

$\hat{\rho}_o = 794 \text{ kg/m}^3$

$\hat{\rho}_w = 1063 \text{ kg/m}^3$

Table 3. Traced Mud Protocol

Reservoir Type	Desire to Measure (By Difference)	Procedure
Gas: Subnormal S_{wi} , No S_o	S_{wi} , (S_g)	Pure oil system or traced WB system
Gas: Subnormal S_{wi} , Subnormal S_o	S_{wi} , S_o , (S_g)	Traced oil system or traced WB system
Gas: Normal or Mobile S_{wi} , No S_o	S_{wi} , (S_g)	Sponge/pressure core, oil system

Gas: Normal or Mobile Swi and Soi	Swi, So, (Sg)	Sponge/pressure core, traced oil system
Oil: Subnormal Swi (oil-wet)	Swi, (So)	Pure oil system or traced WB system
Oil: Normal or Mobile Swi	Swi, (So)	Sponge/pressure core, traced WB
Oil: Mobile Water and Gas	Swi, Soi, (Sg)	Sponge/pressure core, traced WB

Table 4. Example of Water Saturation Calculations Using Tritium Based Coring Program

Sample No.	Depth (m)	Core Perm (mD)	Core Porosity (frac)	Drilling Mud TritiumConcntrn (pCi/ml)	Outer Core Section Data			Middle Core Section Data			Central Core Section Data		
					Measured Sw	Tritium Concntrn pCi/ml	Corrected Sw	Measured Sw	Tritium Concntrn pCi/ml	Corrected Sw	Measured Sw	Tritium Concntrn pCi/ml	Corrected Sw
1	1600	43.70	0.156	6433	0.655	3109	0.338	0.389	1102	0.322	0.345	344	0.327
2	1601	35.40	0.148	6423	0.723	2560	0.435	0.523	1045	0.438	0.456	105	0.449
3	1602	678.20	0.255	6300	0.834	4801	0.198	0.581	4103	0.203	0.411	3260	0.198
4	1603	23.50	0.144	6305	0.588	2690	0.337	0.397	1100	0.328	0.344	333	0.326
5	1604	0.085	0.064	6121	0.788	1045	0.653	0.599	102	0.589	0.567	0	0.567
6	1605	0.022	0.033	5880	0.812	965	0.679	0.633	98	0.622	0.622	0	0.622
7	1606	1.260	0.112	5629	0.634	1467	0.469	0.495	888	0.417	0.417	102	0.409
8	1607	34.60	0.155	5303	0.478	2105	0.288	0.388	965	0.317	0.333	98	0.327
9	1608	23.60	0.166	5333	0.555	1965	0.351	0.399	710	0.346	0.349	122	0.341
10	1609	11.80	0.132	5143	0.499	1322	0.371	0.402	344	0.375	0.370	6	0.370

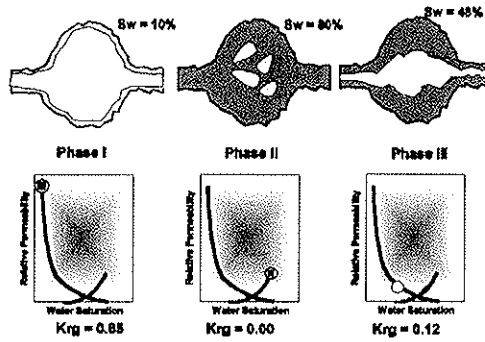


Figure 1 - Basic Pore Scale Mechanism of Water Based Phase Trapping

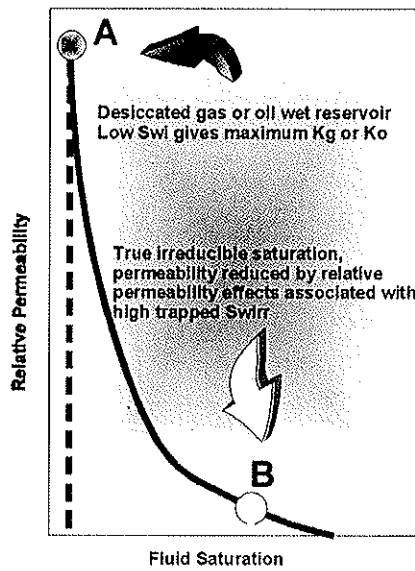


Figure 2 - Illustration of Effect of Trapped Fluid Saturation on Relative Permeability

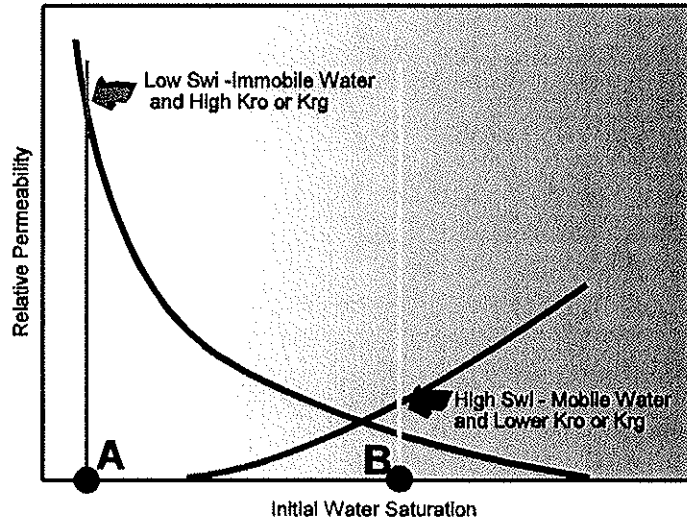


Figure 3 - Effect of Initial Water Saturation on Well Productivity and Water Cut

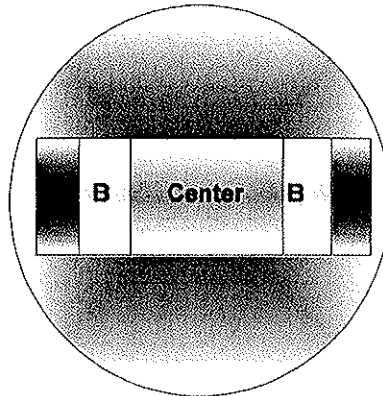
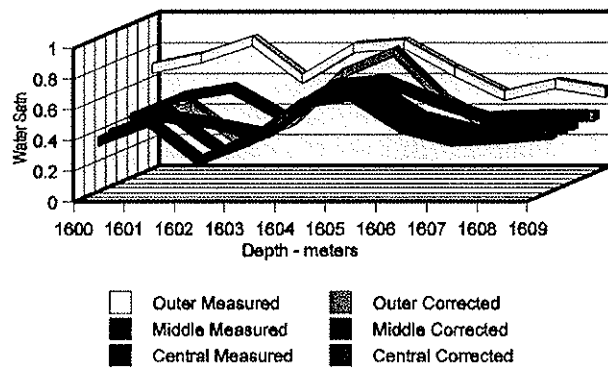
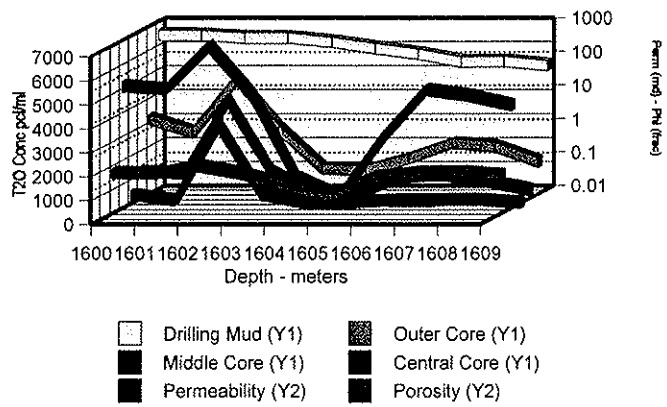


Figure 4 - Typical Sectioning of Core Material for Staged Depth of Invasion Tracer Analysis



**Figure 5 - Tritium Traced Core
Measured and Corrected Water Saturations**



**Figure 6 - Tritium Traced Core
Tritium Concentration Profiles**