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Water Saturation in Tight Gas Reservoirs

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Abstract

Assuming a non-equilibrium scenario most of the non-conventional properties of gas-tight reservoirs are fully explained.

The model is able to describe, among others, the following typical characteristics of these reservoirs: over-pressurization, “abnormal” low water saturation, unusually small or undetectable capillary transition zones, abnormal pressure gradients, reservoir to reservoir disconnection and absence of identifiable free water level.

After accepting de usual over-pressurization as a direct indication of absence of hydrostatic equilibrium, the usual upscaling of capillary pressure curves results meaningless. It is so because capillary pressure was not originated in hydrostatic columns but in over-pressurization occurred when hydrocarbons were expulsed from the source rock (usually in close contact with reservoir rock).

As a result, fluids distribution is affected by non-hydrostatic equilibrium conditions still acting at the time of reservoir discovery.

A specially designed laboratory routine to measure the water saturation and electric properties directly on cores avoiding the usual water column modeling through capillary pressure curves, is presented. The relative permeability curves validity is also discussed.

Introduction

Reservoir engineering calculations usually assume equilibrium conditions. Among these, hydrostatic equilibrium is one of the most commonly “accepted” scenarios.

In spite of this commonly accepted situation, tight gas reservoirs show several non equilibrium indications.

Tight Gas Reservoirs Characteristics. Additional to standard definition based on rock permeability (below 0.1 mD), and economical considerations, the following are some usual technical characteristics of tight gas reservoirs:

- Significant formation thickness.
- Isolated reservoirs inside the same formation.
- Hardly to detect or non existent water transition zones.
- Independent Free Water Level (FWL) for every reservoir.
- Over-pressurized reservoirs.
- “Anomalous” water gradients.
- Water saturation below expected on usual capillary pressure curves interpretation.
- Co-existence or intercalation of source rock with reservoir rock.
- …

Not all of these characteristics are found in every tight gas reservoirs but different combinations of them are usually present.

Among these characteristics a very significant one is the lower than expected water saturation. This situation has received a particular denomination: ***“Sub-irreducible water saturation”***[1].

Unfortunately, the name “Sub-irreducible” suggests some abnormal process whereas, as it will be shown in this paper, water saturation easily exceeds or meets irreducible condition.

It will be shown that measured water saturation is the normal result of the applied capillary pressure while the denomination of ***“Sub irreducible water saturation”*** is a misunderstanding based on the assumption of hydrostatic equilibrium inside the reservoir. In fact, the usually found over-pressurization represents a very strong indication that some non-equilibrium situation governs the reservoir.

Once detected an over-pressurization condition, it may be assumed that this is a final condition or, as geological events suggest, the reservoir is releasing the excess pressure during “geological times”.

In the first case, perfect seals, along geological times, must be assumed. The second scenario only assumes that equilibrium has not been reached yet

The main purpose of this paper is to show that non-equilibrium conditions turns irrelevant the concepts of Free Water Level and “Capillary Transition Zone” associated to fluids distribution in hydrocarbons traps. In fact, as it will be shown, both terms become mathematical calculations with no physical support.

Capillary Pressure Definitions

Different Capillary Pressure definitions exist. Each has its own applicability conditions.

General Definition. Capillary pressure strict definition has a very simple formulation:

$Pc = Pnw - Pw$.. [Eq. 1]

Where

- Pc = Capillary pressure.
- Pnw = Pressure of non-wetting phase
- Pw = Pressure of wetting phase

This general, and always applicable definition, only states that, inside a porous medium, coexisting immiscible phases may have different internal pressure. The phase supporting the higher pressure is known as "non-wetting", and is identified as the phase that must be "forced" to remain inside the poral structure.

Conversely, the phase that remains inside, or invades spontaneously, the porous medium is known as "wetting phase". Its internal pressure is less than that of the non-wetting phase.

***Remark**: The usual definition of "wetting" and "non-wetting" phases is based on contact angle definitions, but, as the concept of "contact angle" itself is hard to define inside complex porous structure, the macroscopic definition is here preferred.*

In spite of its simplicity, Eq.1 has almost no practical applications. Alternative definitions are usually preferred.

Definition under Hydrostatic Equilibrium. In absence of porous medium, two immiscible fluids reach equilibrium condition when the lower density phase remains quietly over the denser one.

In contact with a porous material, the same above mentioned fluids develop capillary pressures derived from the existence of interfacial tensions and a complex interaction between fluids, poral structure and compositions.

In these overall conditions, typical in natural reservoirs[2], stable fluid distribution can only be reached when hydrostatic pressure, derived from different fluids densities, balances capillary pressure by means of the up or down displacement of the fluids interface.

Under these conditions it is possible to re-write the capillary pressure equation as follows:

$Pc = \Delta\delta\ g\ h$ .... [Eq. 2]

Where

- $\Delta\delta$ = Density difference.
- g = Acceleration due to gravity
- h = Interface height, measured from FWL.

***Remark**: FWL is the equilibrium level of fluid interface in absentia of capillary effects.*

Eq. 2 is of direct application on reservoir engineering because all variables are measurable and height has great influence for "in situ" hydrocarbons calculations.

However, when applying this equation the mentioned restriction must be considered: **Eq. 2 can be applied only when hydrostatic equilibrium has been reached.**

- **Question**: "Geological Times" are a guarantee of hydrostatic equilibrium attainment?.
- **Answer**: Usually the answer is affirmative when talking about traps where pressure has attained equilibrium with freatic or surface water. In sub- or over-pressurized systems, equilibrium times may be longer than available "geological time" from the hydrocarbons accumulation event. Also in "exploitation time" periods, hydrostatic equilibrium is usually not reached.

In both above mentioned scenarios, it is of great interest to know fluids distribution in non-equilibrium conditions.

Definition on Simplified Porous Media. Assuming uniform tubular structure for capillaries en porous media it is very easy to obtain the expression:

$Pc = 2\sigma \cos(\theta) / r$ ....[Eq. 3]

Where

- σ = Interfacial tension.
- θ = Contact angle.
- r = Capillary radius

Eq. 3 gives the relationship between capillary forces and the microscopic variables of the system.

But, in spite of its simplicity, Eq. 3 is also limited to situations where variables can be defined. In this case it is very important to remember that "contact angle" and "capillary radius" are hard to quantify in real situations.

Fluid Distribution in Tight Gas Reservoir

Having introduced the equations relating capillary pressure with fluids and porous medium parameters, we will now see the applicability and limits of conventional models in Tight Gas Reservoir description.

From now on, the term "hydrocarbon" will be replaced by "gas" in order to maintain our focus in gas reservoirs, although the following analysis is also applicable to oil reservoirs

Filling the Trap. Reservoir rocks usually present 100% water saturation ($Sw = 100\%$) before hydrocarbon trapping. This reason (added to the "normal" non-wetting condition of gas) accounts for what is known as threshold pressure, the minimum pressure needed to begin water replacement by gas.

In high permeability reservoirs, threshold pressures are so low that hydrocarbons can penetrate the rock with almost any over-pressure generated during "expulsion" from source rock. Additionally, once a minimum gas column height is obtained, subsequent invasion is allowed by the hydrostatic pressure difference between water and gas columns.

In tight reservoirs, threshold pressures are usually higher than 100 psi (about 7×10^6 Pa) and, for pressures and compositions typical of these accumulations, pressures differences of 100 psi are developed between gas and water columns in the order of 100 m. As a consequence, some external source must provide the threshold pressure needed to begin the filling process, before gas columns are high enough to provide an "internal" pressure difference to keep it going.

Fluid Distribution"Anomalies". Only threshold pressure was considered on the previous analysis. To obtain pressure differences high enough to reach typical water saturations for these reservoirs, higher gas columns are needed. Usually

1000 m or more**... in reservoirs that may reach only a few hundred meters thickness!**

Additionally, there are usually clear indications, through well logging and well testing, that the transition zone, if detected, has developed only to a fraction of the expected extension, when estimated from conventional capillary pressure curves.

Explicative Model. These apparent anomalies, along with most of the typical characteristics of these reservoirs, can be explained through a more detailed analysis of the filling process of these traps.

The main assumption of this explicative model is that capillary pressure was not the result of different fluids columns, but the direct application of Eq. 1 where "Pnw" is the gas pressure developed during expulsion from the source rock.

The model is better explained with a physical model such as the one showed in Fig 1.

This model was built with glass spheres packed between two transparent plastic walls. The main characteristic of this model is the heterogeneity created by putting the most permeable medium (high radius glass spheres) in the middle zone (the "central band" called, from now on, "Zone 1"). Both "triangular" zones (called "Zone 2") are made of smaller glass spheres.

In practice, the heterogeneity so generated means a smaller threshold pressure in Zone 1 than in Zone 2.

Initial conditions (showed in Fig.1) represent a 100% water saturated trap.

Fig. 2 shows the first irruption of gas in the trap using an external pressure source, not showed in the picture. In actual reservoir conditions, the external source could be the source rock during the gas expulsion process.

Water is allowed to drain through the opening in the less permeable zone.

Subsequent figures (Fig. 3 and Fig. 4) show successive steps of the trap filling process. All the time the external gas pressure was maintained above the threshold pressure of Zone 1 but below threshold pressure.

At the end of the filling process, Zone 1 attains near irreducible water saturation (Swirr) while Zone 2 remains at Sw = 100%.

- No transition zone is present.
- FWL is a non-sense concept in this scenario.

In fact, it is very easy to verify that all typical properties of tight gas reservoirs can be explained with this model.

- **Over-pressurization**. Is a consequence of the filling process.
- **Anomalous water gradients**. During the displacement, dynamic gradients are over-imposed to hydrostatic gradients.
- **Isolated reservoirs**. If more than one independent structure is filled, each one reaches its own final conditions.
- **Co-existence of source and reservoir rock**. Is the most favorable scenario in order to minimize migration and gas displacement.

What really matters for final water saturation is the maximum over-pressurization ever present and not the over-pressure at the time of reservoir discovering. The back migration of water is a very difficult process not only owed to low absolute permeability but also for relative permeability characteristics: Water left the trap with Sw=100% but, in the return path, permeability is highly reduced by trapped residual gas, occupying the higher radius pores.

This model also explains fractured reservoirs with tight matrix if the trap extends to non fractured, low permeability zones. The model in Fig. 1 will lead to the same result with a "fractured" Zone 1.

Recommended Laboratory Measurements

As a consequence of the model here presented, classical capillary pressure curves are not recommended to characterize fluid distribution in this kind of reservoir.

Fluid distribution is not governed by an equilibrium hydrostatic model, so, most laboratory test, honoring FWL and transition zones concepts will be inadequate.

In fact, real reservoir conditions are impossible to be modeled through laboratory tests by two main factors:

- Time involved and necessary over-pressurization are beyond most routine laboratory equipment.
- Geometric factors that govern the actual accumulation shape at reservoir scale, are not parametric variables. It can't be modeled at laboratory.

As a consequence direct core measurements are suggested. In other words, **our suggestion is to use laboratory only for measurements and not for modeling**.

Cores must be obtained trying to preserve actual reservoir saturation. In fact, the extremely low rock permeability turns to be a favoring factor when trying to preserve water saturation. This fact, joined to a quick coring operation with minimum mud over-pressurization, and the expected gas release during core transport to surface installations, usually leads to a minimum invaded core.

Once at laboratory facilities, after adequately preserving the core, direct measurements should be made. The recommended sequence, according to our experience is the following:

- Plug extraction, discarding the invaded ends.
- Resistivity measurement (temperature and NOBP corrected), to compare with well logging measurements.
- Porosity and permeability on "uncleaned" cores, including NOBP dependence. Porosity is corrected for water content later obtained.
- Plug disaggregation.
- Water content (Dean Stark) on disaggregated cores.
- Salt content.

These direct measurements (porosity, water salinity, water saturation, and resistivity) lead to direct calculation of electrical parameters to be used in well log interpretations.

Conventional porosity and permeability must be tested on "twin" samples, in order to correlate the overall information.

After correction for compressibility, the obtained set of data leads to fluid distribution curves not based on hydrostatic equilibrium assumption.

Permeability measurement on "native" (not cleaned) rocks assures the representativeness of this parameter. Cleaned cores tend to give higher gas permeability estimation, and re-saturation of cores to reservoir conditions is a very difficult task after initial cleaning.

Similar considerations show that conventional relative permeability measurements are not recommended[3]. In this case two main reasons are apparent:

- Fluid displacement is dominated by capillary forces and not by "viscous" forces as demanded by relative permeability concept.
- Piston like displacement is expected. So, only end points have physical meaning.

In fact, the most significant measurement turns to be gas effective permeability as a function of NOBP at reservoir water saturation.

Conclusions

A very simple, non-equilibrium model, shows how all typical tight gas reservoirs characteristics could be explained. This model avoids some arbitrary explanations as "sub irreducible" water saturation or rock desiccation as a consequence of circulating gas through the trap (a process very hard to accept in very low permeability and over-pressurized reservoirs).

The main consequences of this model are:

- No transition zones are expected in these reservoirs.
- FWL is a non-sense concept in tight gas reservoirs.
- Maximum over-pressurization (at any time of geological reservoir history) governs final water saturation
- Original Gas in Situ must be estimated avoiding the concept of FWL, or uniform Gas Water Contact (GWC). The sedimentary structure itself defines the reservoir extension

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Nomenclature

- $\Delta\delta$ = Density difference.
- g = Acceleration due to gravity
- FWL = Free Water Level
- GWC = Gas Water Contact.
- h = Interface height measured from FWL
- NOBP = Net Overburden Presuure
- Pc = Capillary Pressure.
- Pnw = Pressure of non-wetting phase
- Pw:= Pressure of wetting phase
- Sw = Water Saturation.
- Swirr = Irreducible Water Saturation.

References.

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Figures

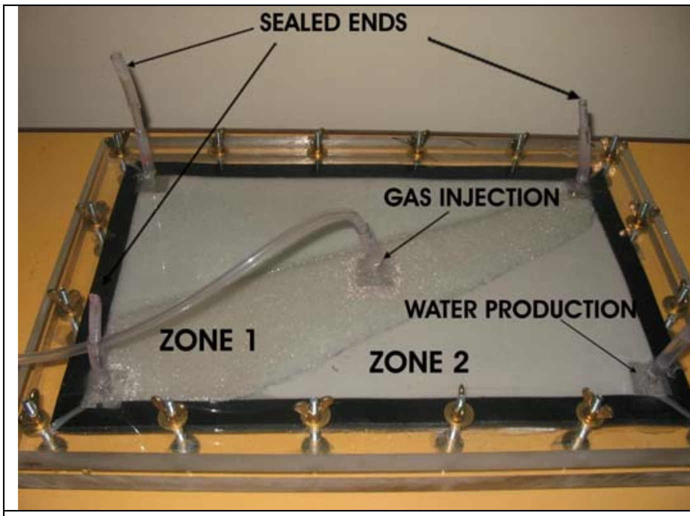

Fig.1: Heterogeneous physical model. Zone 1 has higher permeability than Zone 2.

Fig. 2: Injected gas saturation is appreciable through Zone 1. Water goes out from Zone 2 production end.

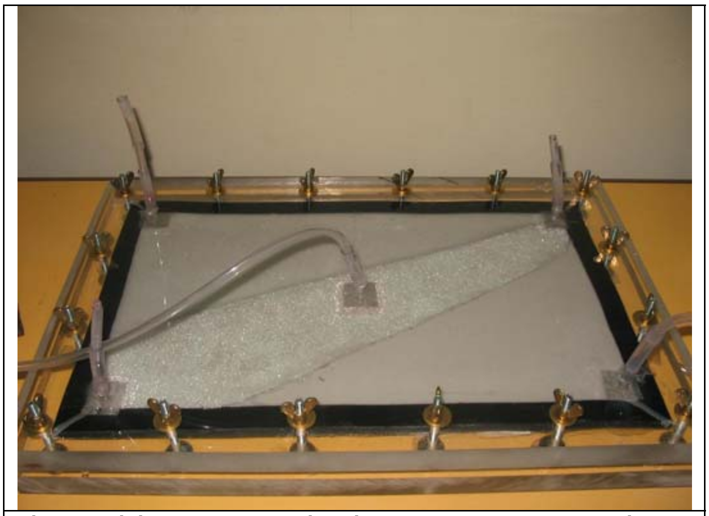

Fig. 3: Higher gas saturation in Zone 1. Zone 2 remains at Sw=100%.

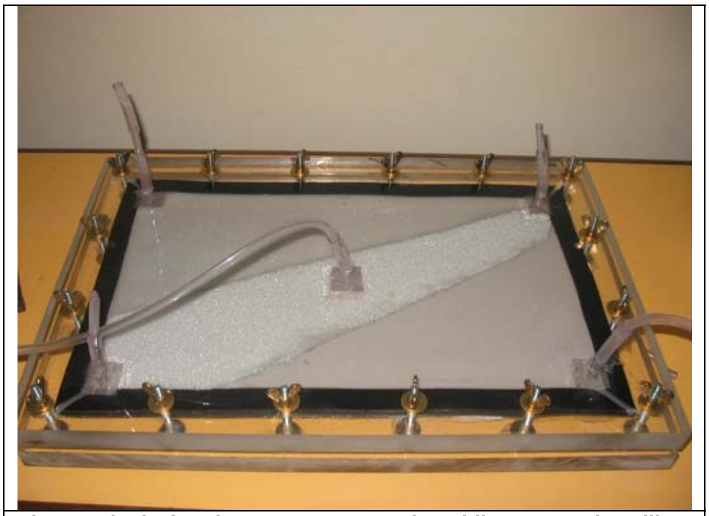

Fig. 4: Final situation. Zone 1 at Swirr while Zone 2 is still at Sw=100%. No transition zone is generated. FWL has no physical meaning