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Laboratory and Field Validation of the Mechanism of Establishment of Very Low Initial Water Saturations in Ultra-Low Permeability Porous Media

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ABSTRACT

The anomalous ability to produce natural gas from very low permeability (<0.05 mD in-situ) intercrystalline matrix sandstones and carbonates has been well-documented on a worldwide basis. This paper illustrates that, in general, for a condition of economic gas production to occur, the initial water saturation that exists in the productive pay must be significantly lower than what would be expected from a normal capillary pressure equilibrium if the matrix under consideration were in dynamic contact with free water. A number of mechanisms for the establishment of these unique non-capillary equilibrium saturation conditions have been postulated over time. This paper presents the theory of long-term regional non-equilibrium gas migration and desiccation as an explanation for this phenomenon, and provides both field and laboratory data that corroborate this mechanism of subnormal initial saturation condition establishment.

INTRODUCTION

With declining production and reserves of 'conventional' natural gas production in higher permeability / pressure formations (1 mD plus), considerable interest and success has been centered in recent years on the exploitation of vast reserves of natural gas contained in 'tight' and 'ultra-tight' sandstones and carbonates. These formations have 'surface' clean core air permeability values generally ranging in the 0.005 to 0.5 mD range and effective 'in-situ' reservoir condition permeability to gas values often in the 0.0001 to 0.05 mD range[1].

The ability of a very low permeability matrix to produce reservoir fluids is controlled by the interaction of several parameters when considering the economic viability of gas production. They include:

1. The absolute permeability of the porous media, dictated by the combination of pore system geometry and interconnectiveness, pore throat size distribution and presence of clays and other authigenic or detrital infilling materials.

2. The degree of overburden pressure/compression effect on the pore system geometry. For low permeability pore systems, this effect is often substantial (1-2 orders of magnitude or more reduction between unstressed 'routine' type surface gas permeability measurements and fully in-situ stressed measurements).

3. The presence/absence of natural micro, meso or macro fractures and the condition (open or infilled) and orientation/interconnectiveness of this natural fracture system.

4. Relative permeability effects associated with the presence of initial trapped or mobile immiscible fluid saturations (oil, water, bitumen, pyrobitumen) present concurrently with the gas in the pore system.

5. Wettability of the porous media controlling the specific distribution of the initial immiscible phase saturations within the low permeability intercrystalline matrix.

For tight gas systems, Criteria 1 and 2 are generally such that the resulting in-situ permeability falls into the 0.001 to 0.05 mD range. In many tight gas systems, a natural fracture network exists, which is usually required in order to access sufficient matrix drainage area to allow economic production rates. In non-naturally fractured systems, large hydraulic fracture treatments (generally 100 or more tons of proppant placed) are usually required in order to access sufficient drainage area.

Interaction of Initial Water Saturation and Relative Permeability Issues in Tight Gas Reservoirs

Although some low permeability gas reservoirs do contain bitumen, pyrobitumen or a liquid in-situ hydrocarbon phase, generally, if this is the case, the effective permeability is often reduced below the economic threshold (considered in most cases to be about 0.001 mD). In most 'producible' situations, connate water forms the secondary immiscible complementary phase to the free gas saturation, and it is this type of system on which this paper concentrates.

Figure 1 provides an illustration of a typical tight gas reservoir pore system cross-referenced to a set of gas-water relative permeability curves. It can be seen that the pore system geometry, coupled with the effective water saturation and location of the water saturation in the pore system, controls the in-situ permeability to gas. The pore system illustrated in Figure 1 is a typical intercrystalline system dominated by microporosity, while that depicted in Figure 2 is a low permeability system where the major flow conduits are either microfractures or limited streaks of laminar, interconnected, larger pores surrounded by microporosity. It can be seen that the relative permeability characteristics with increasing water saturation are substantially different between the two situations, with the effective permeability to gas decreasing more significantly and rapidly in the intercrystalline microporosity-dominated system than in the microfracture mesoporosity-dominated pore geometry. Figure 3 provides comparative gas phase relative permeability data for both types of systems from actual field datasets in a tight gas sand at approximately 2850 m depth with 'routine' surface gas permeabilities in the 0.3-0.8 mD range. It can be seen that there is a large initial reducing effect in relative permeability to gas associated between 0% and 10% initial water saturation (a portion of which is also attributable to overburden compression effects as the test saturation points at 10-40% water saturation are measured with approx. 54 MPa of confining overburden stress, in comparison to about 1.3 for the 'dry' Swi = 0.0 routine permeability measurement). The contrast between the two differing pore system geometries with increasing water saturation is readily apparent from this data set, and it should be noted that for both data sets, a severe reduction in effective permeability to gas as initial water saturation increases is apparent.

The Concept of Subnormal Initial Water Saturation

It has been long recognized that the vast majority of producible 'tight' gas formations have a number of common initial conditions[2-10].

1. Lack of any mobile initial producible water. The only water production generally present from the tight gas zone is fresh water of condensation from the gas phase, generally 1-2 bbl/MMscf of gas.

2. Very high induction log resistivity (100's to 1000's of ohms). This generally results in very low calculated initial water saturations, often in the 5-15% range.

Figure 4 provides a set of 60,000 psi mercury capillary pressure data for a typical 0.10 mD tight gas sand of approximately 8-10% porosity. Figure 4 also provides a complementary plot with the air-mercury data translated into equivalent water saturation as a height above free water contact. This is a very typical data set for an intercrystalline tight gas system. It clearly shows an equilibrium irreducible water saturation at 100 m above a water-gas contact (which would be the maximum pay thickness in a typical tight gas sand producing sequence) in excess of 80%. Translation of this data to a relative permeability basis indicates for this rock that above water saturations of about 60%, gas permeability is effectively immeasurable (<0.000001 mD). This would indicate that, for a reservoir sequence in normal hydrodynamic equilibrium with a free or active water contact, at the equilibrium minimum water saturation which would be expected to exist (even 100 m removed from the contact), no effective permeability to gas would be present and that gas reserves in place would be dramatically reduced by the presence of the high initial water saturation. A reservoir existing in such a saturation condition would clearly be classified as 'wet' pay and would not be a viable gas-producing candidate. This set of circumstances is pictorially illustrated as Figure 5. This is in stark contrast to a conventional higher permeability gas reservoir (Figure 6) of about 85 mD permeability where the capillary pressure curve data are more favorable, resulting in a much lower irreducible water saturation and higher relative permeability to gas at the top of the producing structure. This results in a conventional, viable gas play where, at the top of the structure, high gas rates with little or no free water production can occur.

Examination of the data suggests that, in order for 'tight' gas pay from both a reserves and production perspective, to be viable, some type of non-equilibrium initial water saturation condition must generally exist where the original reservoir sediments are at an initial water saturation significantly less than what would be expected if the pay zone were in capillary continuity with an active water source or contact. This is the formal definition of what are now commonly termed 'dehydrated', 'desiccated' or 'subnormally saturated' low permeability gas reservoirs. The author has, over the past 20 years, observed this phenomenon in a number of regional basins on a worldwide basis as illustrated in Figure 7.

Establishment of the Non-Equilibrium Saturation Condition

Since, by definition, the 'irreducible' water saturation, dictated by the capillary geometry of the rock, normally controls the minimum water saturation existing at any given time and location in a reservoir, a unique mechanism must be occurring in these subnormally saturated reservoir sediments in order to create the non-equilibrium situation that is known to exist at the current time. A number of theories have been proposed over time for the mechanism of subnormal saturation condition establishment; all of which have a common initial progression sequence that includes:

1. Deposition of the original reservoir sediments in some type of marine (100% water saturated) environment (Figure 8A).

2. Influx of hydrocarbon gas initially into the pay zone resulting in displacement of the water saturation down to the initial 'irreducible' level as governed by the capillary equilibrium of the system at that time (Figure 8B).

3. Physical disconnection of the reservoir sediments from active capillary equilibrium with a free water/aquifer recharge source. Possible events would include faulting and tectonics, upheaval erosion and reburial, macrofracturing resulting in large capillary disconnected fault blocks or regional drainage of the initial contacting aquifer (Figure 8C).

This removes the ability of the matrix to recharge itself with water that a reservoir, which is in normal capillary continuity with an active water source, would normally exhibit. Divergent theories exist as to the next transitional phase, which results in the removal of all, or a portion of, the remaining trapped/bound water in the rock to result in the ultimate subnormally saturated condition. They include:

1. Ultra high capillary pressure motivated hygroscopic extraction of the water saturation into highly hydratable associated shales in contact with the formation.

2. Digenetic and pore system changes associated with increased overburden pressure, compression, mineral formation (cementation and overgrowths) as well as long-term formation of authigenic pore filling clays resulting in a reduction of apparent reservoir quality

(and increase in capillary potential), in the absence of recharge from an active water source.

3. Dehydration (evaporation) of the water saturation by transfer into a non-equilibrium gas phase over extended geological time due to extensive regional migration of water undersaturated gas through the sediments of interest (Figure 8D).

Of these three postulated mechanisms, only the third is supported by any significant physical and scientific evidence.

Vaporization Effects as a Means for Subnormal Saturation Establishment – A Case Study

Although the mechanism of long-term regional migration of undersaturated gas from source rock/shales/coals through reservoir intervals as reservoir temperature and pressure increase (which results in increases in the water carrying capacity of the migrating natural gas and also in its non-equilibrium ability to 'leach' water from the trapped liquid phase into a vapor phase in the migrating gas) has long been postulated, little experimental or field evidence is available to support the theory. The following case study [10] of the tight Bossier gas sands provides some of the first combined field and lab evidence of the mechanism of regional gas migration resulting in dehydration.

The Bossier sands are Upper Jurassic in age and were deposited in the East Texas Basin. Located in northeast Texas, this sedimentary basin is a deep elongated trough structure with shelf-slope systems on the basin flanks.

The Bossier sands in Mimms Creek and Dew Fields are comprised of a series of stacked sandy packages as illustrated by the type log in Figure 9. In chronological order of deposition, these packages are known as the York, Bonner, Shelley, and Moore sands. Stratigraphic sequences observed from several whole cores indicate the sands were deposited as a prograding sediment wedge complex during a lowstand onto organic shelf mud deposited during a highstand. At the top of the sand packages, ravinement or transgressive lag deposits have been observed, indicating the onset of a marine transgression during which very little sand was preserved above wave base. The Bossier sands are capped by restricted to open shelfal muds deposited during another highstand.

Typical Bossier sand body geometry is elongated and oriented with the long axis parallel to the depositional dip (Figure 10). Consequently, lateral sand continuity along depositional strike is often limited, resulting in sands with small dimensions and limited continuity. The sand body thickness varies from tens to several hundred feet. The combination of low depositional relief and limited lateral sand continuity minimizes the hydrocarbon column height potential within each sand body. The limited geometry of the isolated sand bodies, the low permeability, and high degree of heterogeneity limits the volume of recoverable gas by a single well. This observation is confirmed from production decline type curve analysis that indicates small drainage areas, typically less than 40 acres per well.

Wells completed in the Bossier sands produce a lean gas with specific gravity ranging from 0.58 to 0.61. Condensate production averages one to three STB/MMscf over the life of the well indicating a 'dry' non-retrograde type of gas system at bottomhole pressure and temperature conditions. Gas composition typically averages 94 mole percent methane and 2 mole percent ethane. The remaining hydrocarbon mixture includes fractional percentages of propane through hexane with typically no heptanes plus. Non-hydrocarbon components include 2 to 2.5 mole percent carbon dioxide, 0.2 to 0.5 mole percent nitrogen, and relatively no hydrogen sulfide.

The Bossier produces some water; however, it is thought that no mobile liquid water phase exists in the reservoir. Laboratory analyses indicate five to seven mole percent of water vapor may be dissolved in the gas at reservoir conditions. Consequently, most of the low water production rate over the life of a well can be attributed to condensed water vapor.

Figure 11 shows a typical distribution of Bossier sand porosity and permeability. Effective porosity varies from 1% to 17%, while absolute permeability ranges from 0.001 to 1 mD. Non-reservoir and seal rocks have permeability values lower than 0.0001 mD. In general, the Bonner and York sands have better permeability and porosity than the Moore and Shelley sands. Better reservoir quality combined with higher pressures is demonstrated by greater gas recovery.

Similar to most tight gas sands, the Bossier sands display both stress-dependent porosity and permeability characteristics. For example, the hyperbolic decline behavior exhibited by many tight gas sand wells can be attributed, in part, to reductions in permeability and porosity during the depletion history. Porosity and permeability were measured over a wide range of stress conditions and only slight changes in porosity were observed. However, significant reductions in permeability as net pressure increased. It was also observed that the degree of stress dependency increased for the lower quality rock types.

Although no mobile liquid phase exists in the Bossier sands at reservoir conditions, the presence of water does affect gas flow capacity. Consequently, effective gas permeability was measured for a range of water saturations. Figure 12 shows computed relative permeability curves for hydraulic rock types 1, 2A and 2B. All of the curves were normalized to 5% initial water saturation based on the minimum water saturation measured in rock type 1. Note that, for the entire range of hydraulic rock types, the effective permeability to gas is reduced significantly for water saturation greater than 40%.

Connate (initial) water saturation was measured from more than 300 Bossier core plugs. Since the whole core was obtained with a low invasion pure oil-based mud system, it was possible to obtain consistent and accurate estimates of in-situ connate water saturation. Most of the non-reservoir rock had water saturation greatly exceeding 60%. Measured water saturation in the best reservoir rock (still with effective permeability of less than 0.01 mD), however, averaged 5% (and increased to up to 60% in the very poor flow units). These measured water saturations, especially in the best reservoir rock, were significantly lower than expected.

Capillary pressure characteristics were measured using high-pressure, mercury injection (MICP). This method was used since the low porosity and permeability precluded using either centrifuge or porous plate methods that are limited by the maximum attainable pressure

The vertical distribution of water saturation in the same wells from which the core was obtained was also computed via log analysis. The best match between core-based and log-based water saturation was obtained with the modified Simandoux shaly sand model. Shale volume was estimated from the gamma ray response and porosity cross-plot techniques. Effective porosity was computed using neutron-density cross-plot techniques and was corrected for shale and gas effects.

Application of the modified Simandoux model also requires estimates of the Archie saturation exponent, n, and the cementation exponent, m. These parameters were measured in the laboratory using both two- and four-electrode resistivity devices. Core samples were saturated using a 220,000 ppm brine, and all measurements were made at initial reservoir conditions, *i.e.*, 3500 psia net stress and temperature of 300°F. Results from both two- and four-electrode devices were in close agreement. The average values of m and n were 2.15 and 1.85, respectively. Excess conductance was measured using the Co/Cw method. Average corrected values of m^* and n^* were 2.2 and 1.87, respectively. The effect is minimized by the highly saline connate water.

The final component required to compute connate water saturation is water resistivity, R_w, at reservoir conditions. Unfortunately, direct sampling and testing of the formation water is impractical in the Bossier sands in the Mimms Creek and Dew Fields. As mentioned previously, this is typical for subnormally saturated tight gas reservoirs due to the very low apparent initial water saturation, which results in zero effective mobility of the connate water phase. Initial water produced from the Bossier is mostly fracturing fluids from the stimulation treatment. The water production following fracturing is condensed water of vaporization with a very low salinity. Consequently, we used commutation analysis and fluid inclusion micro-thermometry to estimate connate water salinity.

Commutation or residual salt analysis is a process that extracts or leaches connate water and the associated salts from preserved core samples using ultra-pure, de-ionized water. Salt concentration and composition in the leachate are measured using an atomic absorption or mass spectrometer technique, while salinity is estimated from material balance calculations. Salinity measurements on the in-situ brine indicated the small water saturation present was saturated (300,000 ppm TDS plus), and additionally that large volumes of crystalline salt (predominantly halite) were present in the pore system, verifying the fact that the initial water saturation had once been considerably greater than currently present. Gradual dehydration of the water saturation by regional desiccation resulted in eventual supersaturation of the ever decreasing connate water saturation and, finally, precipitation of large amounts of elemental salt from the water phase when, as its volume decreased, the solubility limit was exceeded. This is very compelling evidence for the mechanism of dehydration as the establishing root cause for the subnormal water saturation condition which exists in the Bossier sand packages.

Fluid inclusion micro-thermometry (FIT) uses thin sections from core samples to measure the temperature at which fluid inclusions melt. This melting temperature is directly related to the connate water salinity. Results from the FIT analysis were consistent with the high measured brine salinities from the commutation analysis.

In general, results from the log-based analysis agreed with water saturation estimates from the core analysis in the reservoir rock. An example of this agreement is illustrated in Figure 13.

In many cases, the concentrating effect of the desiccation process on remaining connate water salinity may lead to an over-estimation of the initial water saturation by conventional log analysis methods. It can be seen that, since no connate water production is common in tight gas reservoirs of this type, regional water analysis of produced water from non-dehydrated reservoir sources are often used to approximate the initial connate water composition. These non-dehydration process exposed brines are often significantly fresher in nature than their desiccated reservoir counterparts and hence exhibit higher resistivity. This results in the prediction of elevated water saturations when using the lower salinity in the log evaluation calculation. In the authors' experience, this often results in the already fairly low water saturations commonly evaluated in tight gas reservoirs from a logging perspective still being higher than those actually present, unless a corrected commutation-based water analysis is used in the log evaluation process. This is apparent to a limited extent in Figure 13 where the measured Swi values in general are slightly less than the log-calculated data (220,000 ppm salinity was used in the log calculations).

As discussed previously, attempts were made for the Bossier sands to compute a vertical distribution of water saturation from capillary pressure characteristics. Mercury capillary pressure data were converted to height above free water and plotted against water saturation. Current understanding of the geology in the Bossier sands in the Mimms Creek and Dew Fields indicates the sands were deposited on a low relief shelf/slope topography and appear to be laterally discontinuous. Under these conditions, the total relief is about 200 ft. Using a 200-ft total column height, the computed range of irreducible water saturation is 35% to 100% for the reservoir rocks. This range, illustrated in Figure 14 as the dashed horizontal line, is significantly greater than the core-based measurements and log-based calculations.

Because of these discrepancies, our next step was to determine the column height required to match the range of water saturations determined from core and log analyses. Our calculations indicate an average total column height of 1000 ft is required to generate irreducible water saturations from 5% to 55%. Current depositional and geological models of the Mimms Creek and Dew Fields do not, however, support anywhere near a 1000 ft column height.

In summary, vertical distributions of core-derived measurements and log-derived calculations of water saturation cannot be matched with estimates from capillary pressure characteristics unless unrealistic assumptions about sand geology and structure, particularly column height, are made. This observation suggests the vertical distribution of water saturation in the Bossier sands may not be in capillary equilibrium. In fact, measured water saturation is much lower than that which would be predicted by capillarity, *i.e.*, a sub-capillary-equilibrium or sub-irreducible water saturation condition.

CONCLUSIONS

This paper has discussed the phenomena of sub-normally low non-equilibrium initial water saturations in very low permeability gas reservoirs. The following conclusions can be drawn from this work.

1. Reservoirs exhibiting a combination of low absolute permeability and low initial water saturation are present on a worldwide basis, particularly in basin centered geological developments.

2. In most cases of tight gas matrix production (in-situ permeability to gas 0.05 mD or less), a subnormal initial water saturation condition must exist to both increase reserves and potential production rates, even in the presence of natural or induced fracturing, to economic levels.

3. A number of theories have been postulated for the establishment of the low water saturation condition. The theory with the greatest degree of physical support from both a laboratory and field perspective is that of desiccation effects cause by long-term regional migration of undersaturated gas from source rock adjacent to the ultimate tight gas producing intervals. The process is generally believed to follow the chronology of:
    a. Initial deposition of sediments in marine environment.
    b. Initial displacement to true Swirr by primary gas displacement.
    c. Hydraulic disconnection of sediments from active water contact by tectonic or other events (can occur before or after point 'b').
    d. Long-term migration of undersaturated gas through pay zone resulting in gradual transfer of water saturation from liquid to gas phase.
    e. Results in current reservoir environment of low permeability combined with low to very low initial water saturation.

4. A case study in the Bossier sandstones in Texas confirms this mechanism through a specially executed extensive program of oil-based coring and core analysis, capillary pressure studies and commutation analysis, and fluid inclusion analysis for connate water composition. Comparative evaluation of the measured saturation data with known capillary transition data confirms that a condition of subnormal water saturation must exist in the reservoir.

5. Formation damage effects due to fluid trapping of both water and oil based filtrates may be significantly more pronounced in these types of formations, depending on the degree of increase in trapped fluid saturation and the configuration of the gas phase relative permeability curves in the region of increasing trapped fluid saturation.

6. The mechanism of desiccation results in an increase in remaining liquid connate water phase salinity, which in turn suppresses true in-situ Rw. This may lead to overestimation of water saturation using conventional log analysis methods where regional water resistivity values from non-dehydrated, water-producing regional formations are used to evaluate water saturations in dehydrated matrix situations.

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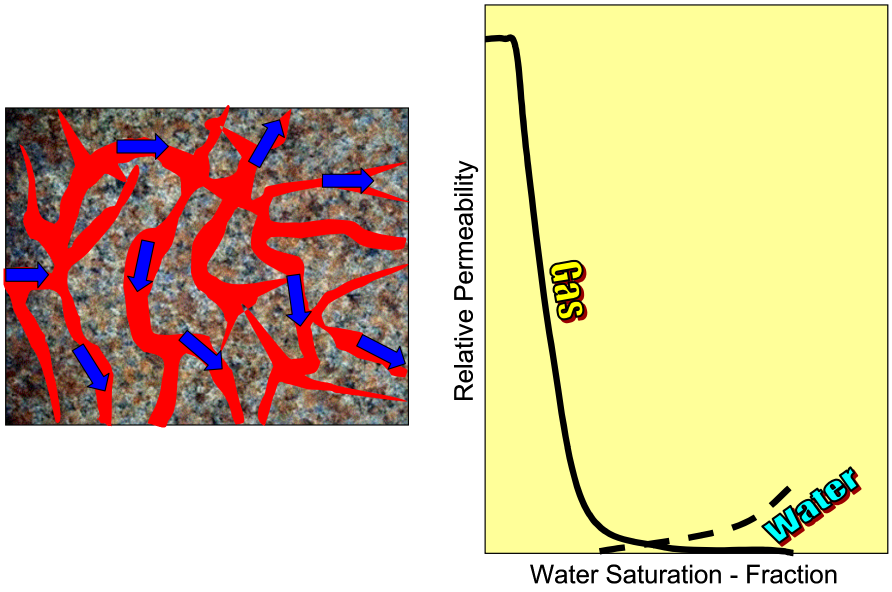

Figure 1: Illustration of Typical Tight Gas Water-Gas Relative Permeability Curves in a System Dominated by Intergranular Microporosity

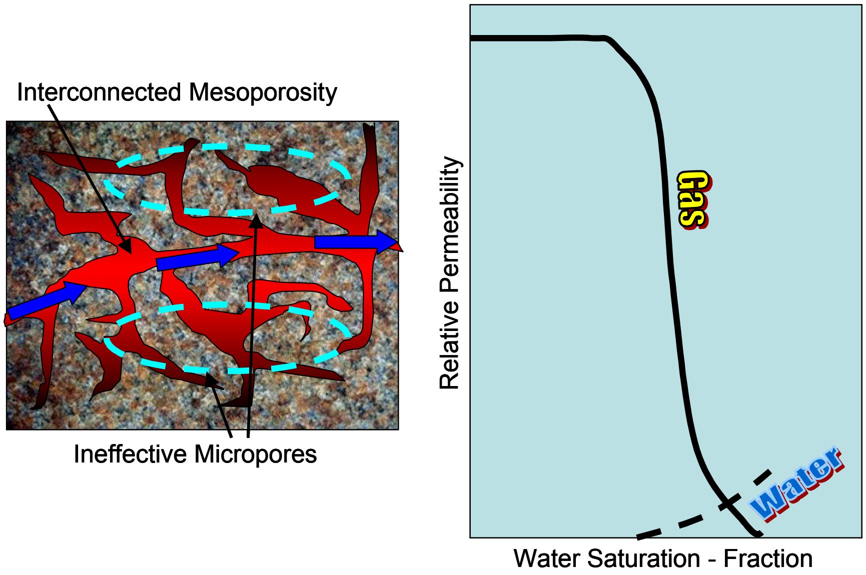

Figure 2: Illustration of Typical Tight Gas Water-Gas Relative Permeability Curves in a System Dominated by Mesopores with Connected Ineffective Microporosity

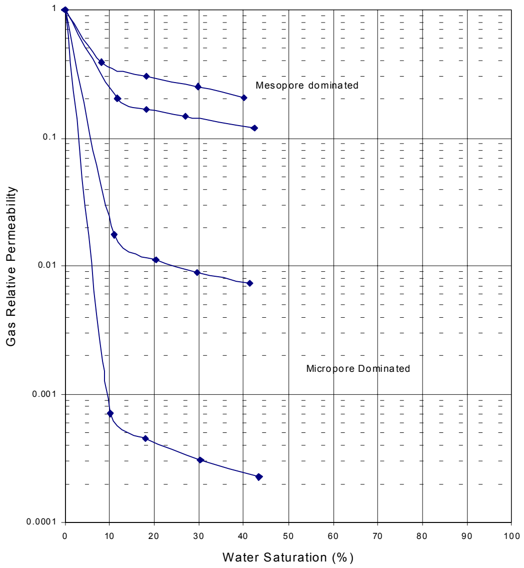

Figure 3: Illustration of Gas Phase Relative Permeability Character vs Increasing Water Saturation for Micro and Meso Pore-Dominated Tight Gas Systems

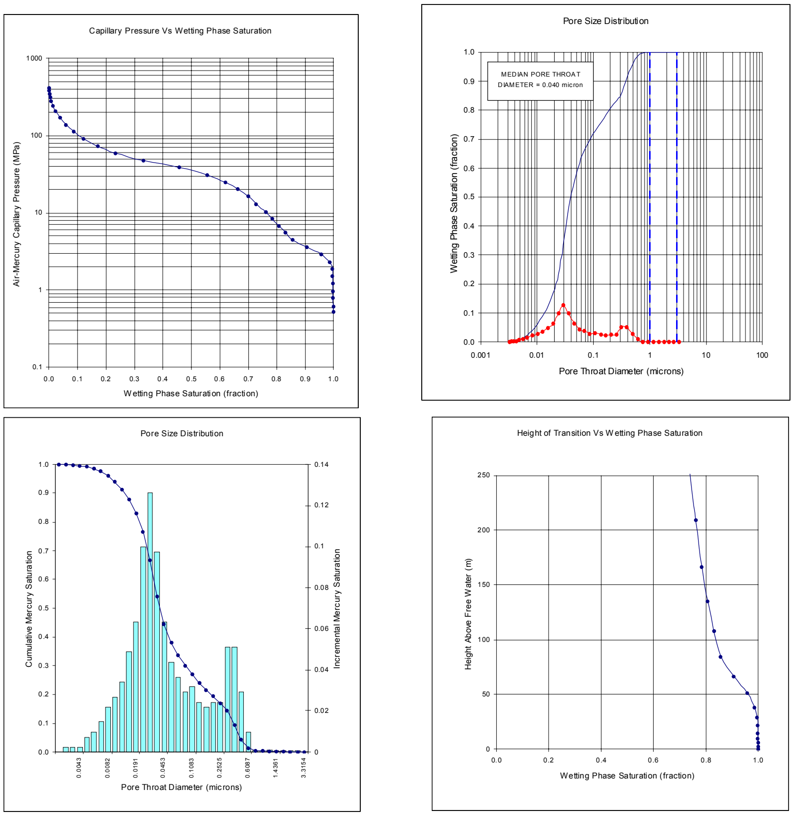

Figure 4: Typical Tight Gas Cap Pressure Data

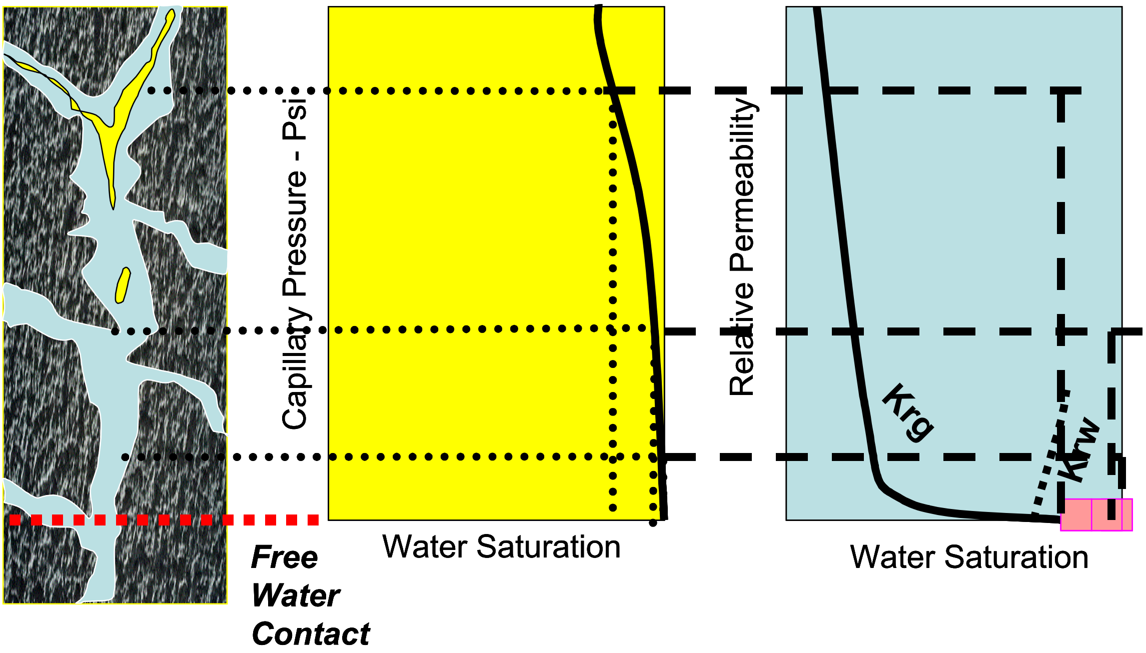

Figure 5: Capillary Equilibrium in Gas Reservoirs – *Low* Permeability

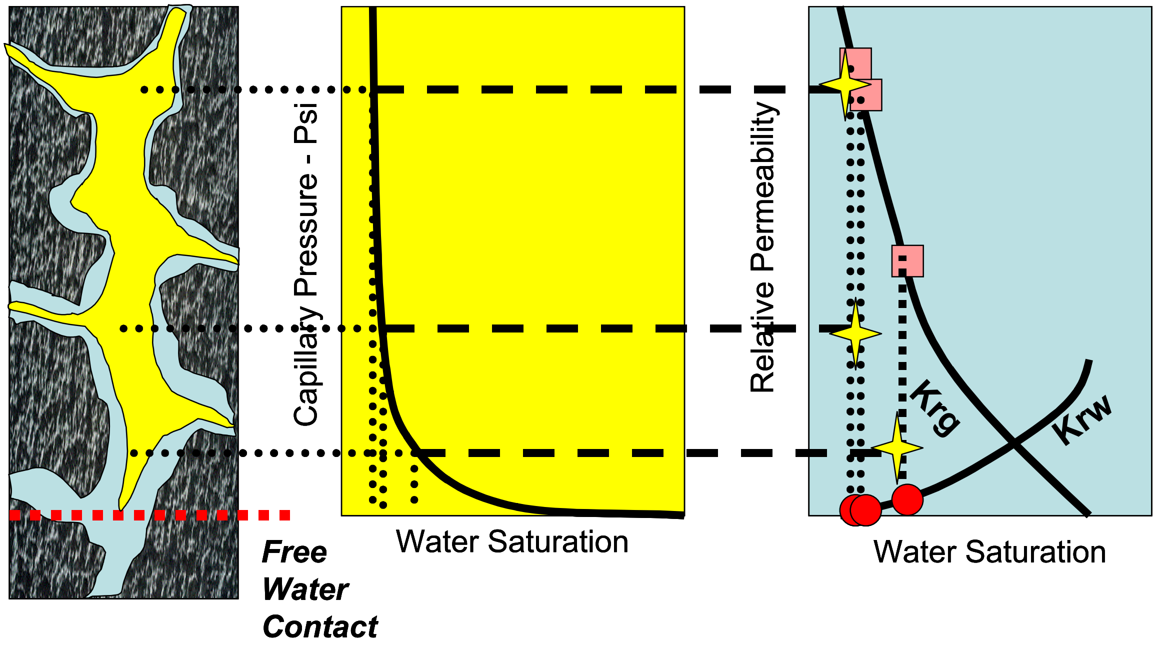

Figure 6: Capillary Equilibrium in Gas Reservoirs – *High* Permeability

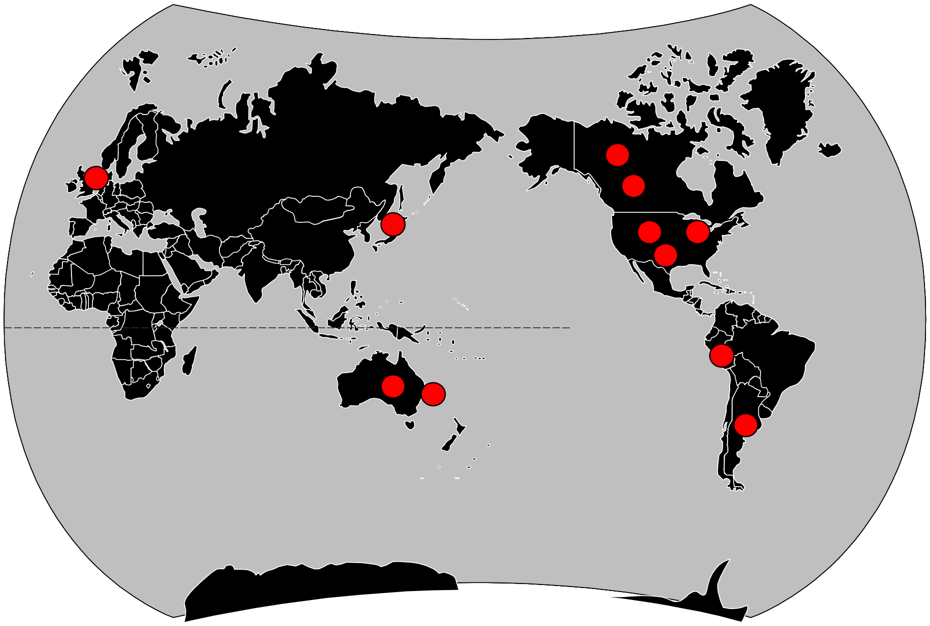

Figure 7: Known Locations of Subnormally Saturated Tight Gas Producing Basins

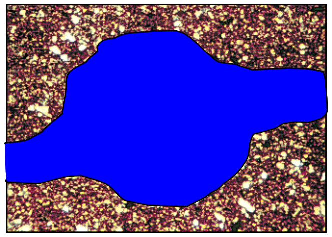

Figure 8A: Original Deposition of Sediments in Marine Environment

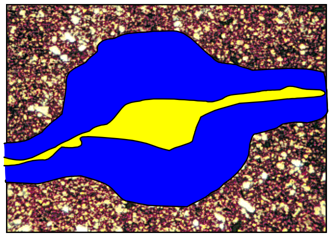

Figure 8B: Primary Gas Influx and Displacement to Capillary Swirr

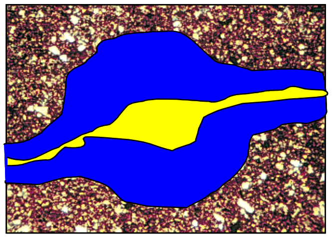

Figure 8C: Hydraulic Disconnection from Active Water Recharge/Contact

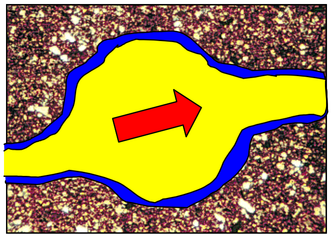

Figure 8D: Long-Term Regional Gas Migration Dehydrates Water Saturation to Capillary Subnormal Level

Figure 8: Illustration of Mechanism of Subnormal Water Saturation Creation in Porous Media

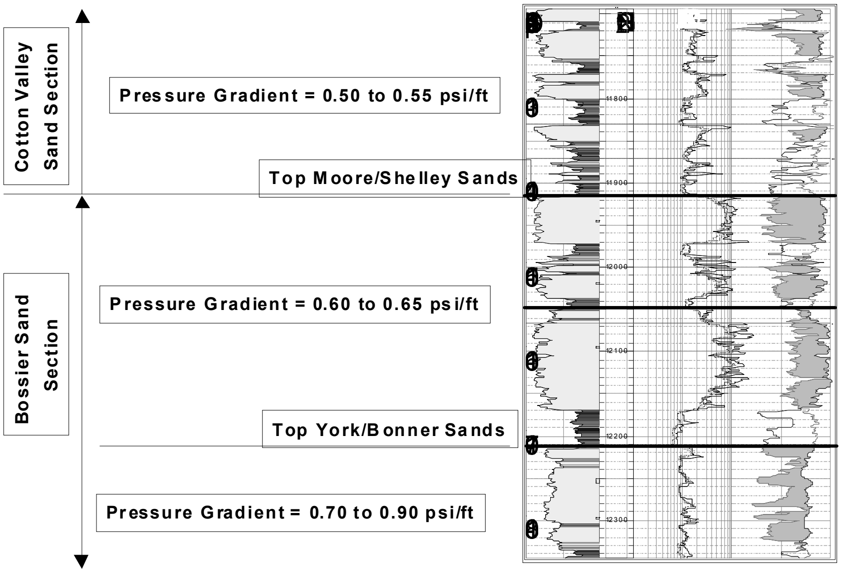

Figure 9: Type log of the Bossier Sands showing the range of observed pressure gradients and the sequence of sand deposition.

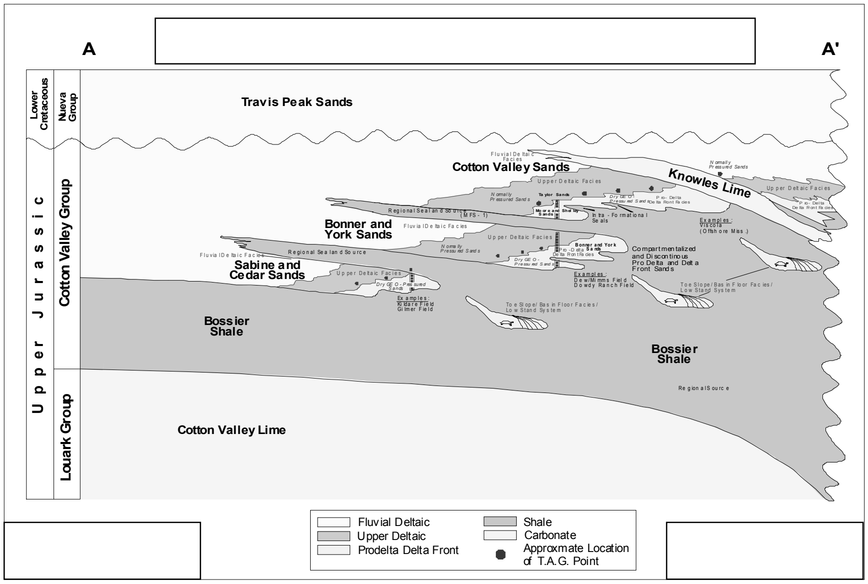

Figure 10. Generalized regional dip-section of the Bossier facies. Sand deposition represents cycles of sand progradation into the basin onto organic rich mud, succeeded by marine transgression. Much of the Bossier shales down dip appear to be time equivalent to the up dip Cotton Valley Sandstone and represent pro-delta/delta front material related to Cotton Valley deltaic systems (drawing courtesy of Jim Tautfest, Anadarko Petroleum Corp., 1999).

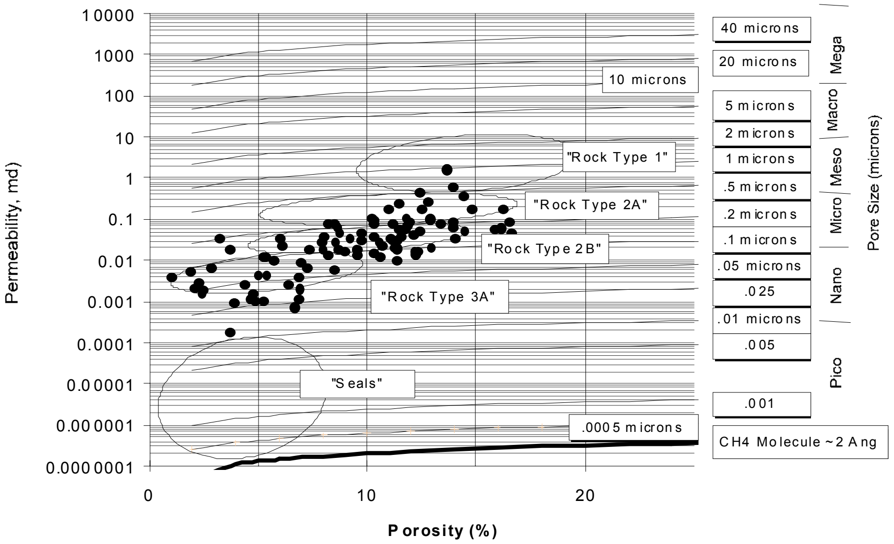

Figure 11. Porosity and permeability plot that shows the general region of each rock type (ovals) for the Bossier Sand.

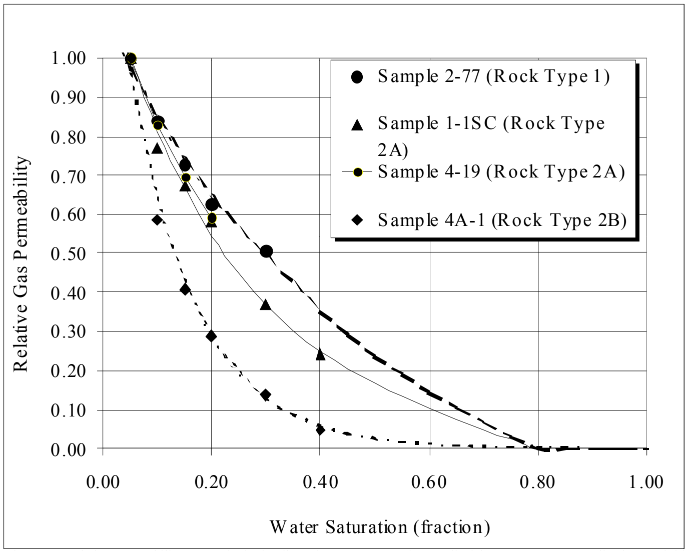

Figure 12. Relative permeability curves for hydraulic rock types 1, 2A and 2B. All of the curves were normalized to 5% initial water saturation based on the minimum water saturation measured in rock type 1.

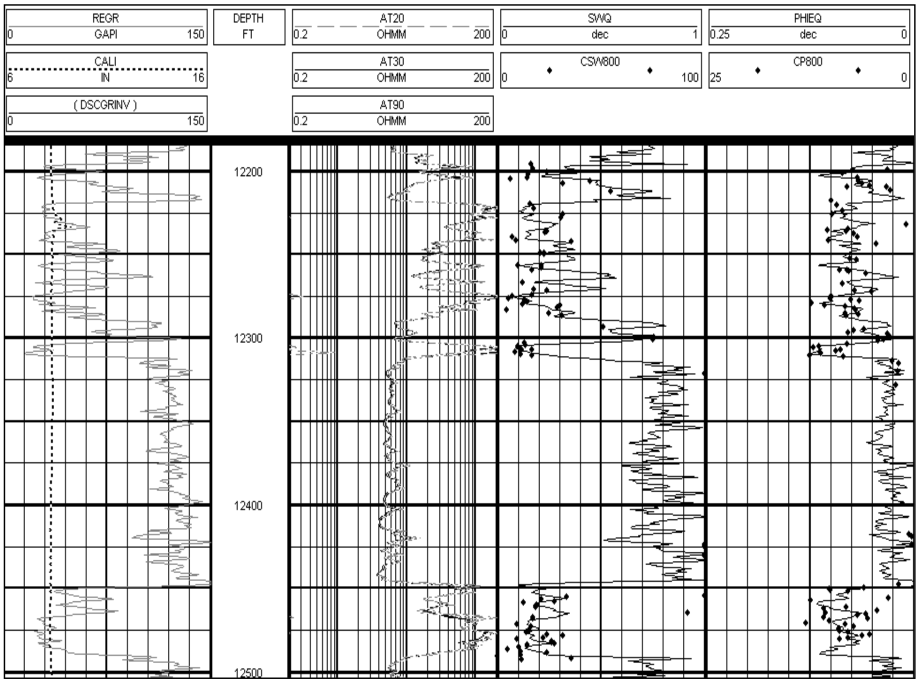

Figure 13: Illustration of Log and Core (Black Dots) Measured Water Saturations

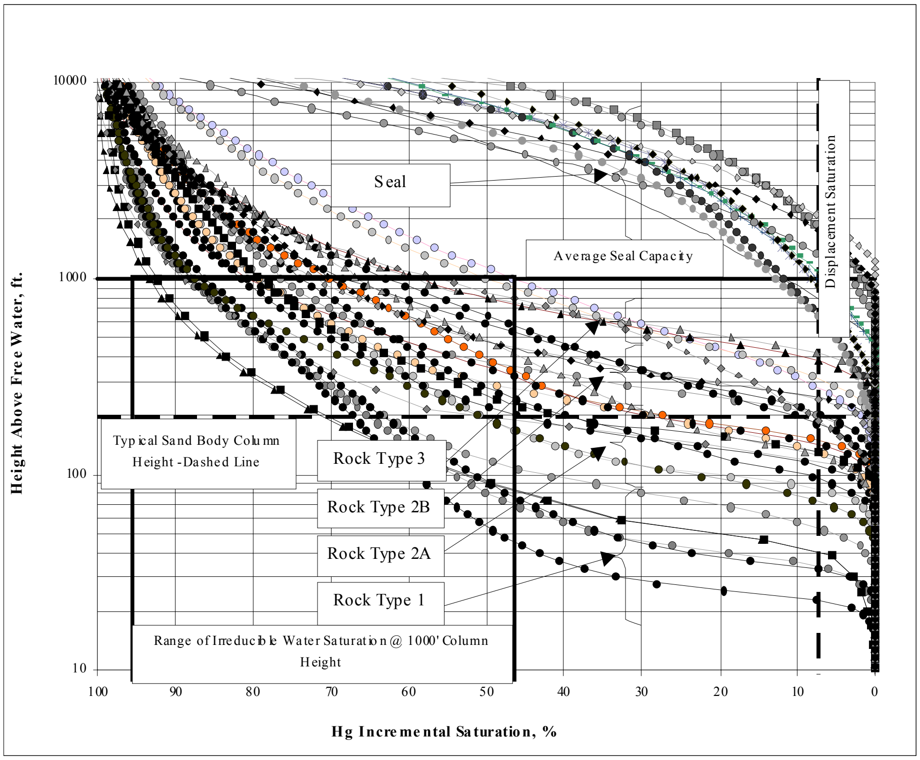

Figure 14: Illustration of Height Above Free Water Data From Field Analysis