Low Permeability Gas Reservoirs and Formation Damage - Tricks and Traps

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Abstract
As drilling and completion technology advances, the trend to exploitation of gas reservoirs exhibiting ever lower permeabilities continues. This paper discusses issues associated with the identification of productive, low permeability, gas-producing formations and the successful completion and production of these reservoirs. For the purposes of this paper, a very low permeability gas reservoir is defined as a formation having an in-situ matrix permeability to gas of 0.5 mD or less. Criteria are presented for identifying economic absolute permeability cutoffs for low permeability gas-bearing formations. Very low permeability gas reservoirs are typically in a state of capillary undersaturation where the initial water (and sometimes oil) saturation is less than would be expected from conventional capillary mechanics for the pore system under consideration. These formations are commonly referred to as dehydrated or desiccated formations and have been documented on a worldwide basis. Retention of fluids (phase trapping) is discussed as one of the major mechanisms of reduced productivity, even in successfully fractured completions in these types of formations. As well, a variety of diagnostic and remedial treatment options are presented.

Introduction
As the oil and gas industry matures, ongoing reservoir targets move towards more challenging applications commonly exhibiting low permeability and often low pressure. One particular area which has received increased emphasis in recent years is the production of gas from extremely low permeability formations. Considerable effort has been expended in a number of areas in the Deep Basin area in Canada, the Powder River Basin in the Central United States and in the Permian Basin in the Texas area in attempting to exploit gas reservoirs with average in-situ permeability in the 100 micro-Darcy (0.1 mD) or less range.

This paper details a number of issues which center around the ability to first diagnose whether a particular reservoir will be an economic candidate for viable gas production and secondly, to evaluate what are the best drilling, completion, and ultimate production practices for such wells to obtain the maximum flow rates and ultimate recoverable reserves of natural gas.

What is a Low Permeability Gas Reservoir?
The definition of a low permeability gas reservoir is arbitrary but, for the purposes of this presentation, we will consider such a reservoir to be a reservoir matrix which has an effective in-situ permeability to gas of 0.5 mD or less. Although such permeabilities would be prohibitive for the economic production of conventional crude oil, they may still be feasible for gas production. In many situations, due to the low inherent viscosity of natural gas, the initial pressure of the producing formations, if sufficient reservoir penetration and exposure to the low permeability producing zone can be obtained in an economic fashion, long-term production of significant volumes of gas may be realized.

The Traps!! When addressing the potential productivity of the low permeability gas reservoir, three major issues are of paramount concern.

1. Does the reservoir exhibit sufficient initial permeability and pressure to facilitate economic gas production rates, even in...
the presence of a successful large-scale stimulation treatment?

2. Are the initial water and liquid hydrocarbon saturations that are trapped within the reservoir matrix low enough to create sufficient gas reserves in place and adequate initial permeability for economic gas production?

3. What potential forms of formation damage can occur during drilling and completion operations or subsequent production operations, that may reduce the ultimate productive capacity of the reservoir?

**Initial Permeability.** As drilling and completion technology improves, we realize we are in a position to produce gas from even lower quality formations. Large-scale hydraulic fracture treatments in reservoirs with average permeabilities as low as 5-10 µD (0.005 - 0.010 mD) have been successful. In the absence of an interconnected natural fracture network, which may assist in the drainage of a low permeability matrix system, this permeability range appears to be a reasonable cutoff value for economic gas production rates using the level of current completion technology. The value of this cutoff will, of course, be highly dependant on a number of other factors, most notably the original reservoir pressure available for production. If a subnormally pressured or pressure depleted reservoir is under consideration, the effective permeability cutoff for economic gas production rates may be substantially higher than this value of 5-10 µD.

**Initial Water and Liquid Hydrocarbon Saturations.** The value of the initial water and liquid hydrocarbon saturation that are contained within an intercrystalline matrix system in a gas-producing reservoir are generally controlled directly by the capillary pressure of the porous media under consideration. Capillary pressure can be defined rigorously as the pressure differential existing between the non-wetting phase [gas] and the wetting phase [water and/or hydrocarbon liquid]. Capillary pressure can also be derived using a number of other formulations, including the classic height above a free water contact relationship and also the equilibrium summation of mean radii of fluid interfacial curvature. These respective equations are illustrated below:

\[ P_c = P_{mv} - P_w = \Delta \rho gh = 2\sigma \cdot \frac{\cos \theta}{R} = \sigma \left( \frac{1}{R_1} + \frac{1}{R_2} \right) \]  \hspace{1cm} (1)

Fig. 1 provides a schematic illustration of the radii of curvature referred to in the specific calculation of capillary pressure in porous media. Figures 2 and 3 provide an illustration of typical irreducible water saturation profiles in both low permeability (Fig. 2) porous media and high permeability (Fig. 3) porous media. In Figure 3 it can be observed that, in a high permeability rock, the porous media is generally characterized by large, open pore throats and pore bodies. We can see that this geometry leads to relatively large radii of curvature in the gas-liquid interfaces in the porous media. Since capillary pressure is given by the sum of the inverse of these radii of curvature, it can be seen that the capillary pressure values tend to be relatively small, even at low water saturations. This is why high permeability porous media with no or limited micro-porosity usually tends to exhibit favorable capillary pressure characteristics with low capillary pressure values over the majority of the mobile saturation range and relatively low irreducible water saturations.

Figure 2 provides an illustration of an equivalent situation in a low permeability gas reservoir. In this case, due to the very small size of the pore throats and pore bodies, the tortuous nature of the pore system and high degree of micro-porosity, the observed radii of curvature of the gas-liquid interfaces are very small, particularly at low water saturations, which gives rise to the higher capillary pressure values and irreducible water saturation values which are commonly associated with poor quality porous media.

Fig. 4 provides an illustration of typical curves for capillary pressure for different quality porous media. In general, as permeability and porosity are decreased and the relative fraction of micro-porosity increases, both the capillary pressure value and the value of the irreducible water saturation tend to increase substantially.

Often associated with this increase in trapped initial liquid saturation is a significant reduction in net effective permeability to gas in the porous media caused by the occlusion of a large portion of the pore space by the irreducible and immobile trapped initial liquid saturation present in the porous media. This phenomena is schematically illustrated as Fig. 5. On a relative permeability basis (Fig. 6), one can observe that, in general, the greater the value of the initial trapped fluid saturation, the less original reserves of gas in place available for production, and also the lower the initial potential productivity of the matrix.

In reservoir situations where exceptionally low matrix permeability is present, one finds that, if the reservoir is in a normally saturated condition (that is, if the reservoir is in free contact and capillary equilibrium with mobile water and is at a normal level of capillary saturation for the specific geometry of the porous media under consideration), we find that very high trapped initial liquid saturations tend to be present. Fig. 7 provides a schematic illustration of "average" irreducible water saturations expected for porous media of typical permeability ranges. The permeabilities given in Fig. 7 represent average, uncorrected routine core analysis permeability data for a matrix-dominated reservoir situation (no fracturing present). One can observe that in reservoir rock of permeability to gas on an absolute basis of less than 0.1 mD, effective initial water saturations are often in the 60% plus region. This often results in significant reductions of the original reserves of gas in place in the porous media, and may also result in a very low or zero effective permeability to gas, as the gas saturation may be at or near the critical mobile value and hence it will exhibit limited or no mobility when a differential pressure gradient is applied to the formation during production operations.

Therefore, it can be observed that in most cases where very
low permeability gas reservoirs are potentially productive, the reservoir exists in a situation where the reservoir sediments have been isolated from effective continual contact with a free water source which is capable of establishing an equilibrium and uniform capillary transition zone. It appears that a combination of long-term regional migration of gas through the isolated sediments (resulting in an extractive desiccating effect as temperature and pore pressure are increased over geologic time), or an osmotically-motivated suction of connate water into highly hydrophilic clays or overlying/interbedded sediments, may be responsible for the establishment of what is commonly referred to as a "sub-irreducible" initial water saturation condition.

A reservoir having a sub-irreducible initial water saturation is defined as a reservoir which exhibits an average initial water saturation less than the irreducible water saturation expected to be obtained for that porous media at the given column height present in the reservoir above a free water contact (based on a conventional water-gas capillary pressure drainage test). Significant discussion is present in the literature on the establishment and diagenesis of sub-irreducibly saturated gas reservoir systems (Ref. 1-5). Many reservoir systems of this type have been extensively characterized in the Deep Basin area of Canada, the Powder River Basin area of the United States and the Permian Basin area in Texas.

In situations where exceptionally low matrix permeability is present in a gas-producing reservoir, unless a sub-irreducibly saturated original condition is present, the reservoir will exhibit insufficient initial reserves/permeability to be a viable gas-producing candidate. Therefore, with few exceptions, the vast majority of ultra-low permeability gas reservoirs that would be classified as exhibiting economic gas-producing pay, would fall into this classification of subnormally saturated systems. This phenomena will be discussed in greater detail further on in the paper as it gives rise to one of the most severe potential damage mechanisms in low permeability gas reservoirs, that of fluid retention or phase trapping.

Formation Damage Mechanisms in Low Permeability Gas Reservoirs During Drilling, Completion, and Production Operations

Formation damage is an expansive topic which has been discussed in detail by many authors in the literature (Ref. 6-10). In this paper, primary attention is given to mechanisms of formation damage which often tend to be the most prevalent causes of reduced productivity in low permeability gas reservoirs. These damage mechanisms predominantly fall into the following three major classifications:

- Mechanical formation damage mechanisms
- Chemical formation damage mechanisms
- Biological formation damage mechanisms

Mechanical Formation Damage Mechanisms

The following problems tend to be the most significant for low permeability gas reservoirs.

Fines Migration. This refers to the motion of naturally occurring in-situ particulates within the pore system caused by high interstitial fluid velocities induced by differential pressure gradients. In general, fines migration tends to be most significant when the wetting phase of the reservoir is in motion. Typically, under conditions of pure gas flow commonly associated with a low permeability gas reservoir, fines migration problems tend to be minimized, as the wetting phase (usually water) in which the mobile fines are encapsulated does not move, and hence, insulates the fines from the majority of the interstitial shear associated with the motion of the gas in the pore system. For this reason, in most low permeability gas reservoirs, fines migration does not tend to be a major issue since, due to the low initial fluid saturations which are generally present, no mobile liquids are typically present in the matrix. In addition, many of these reservoirs tend to be at significant depth and have undergone significant compaction and diagenesis which has often removed or cemented most reactive or mobile clays. Fines migration may be potentially problematic in situations where significant volumes of water or hydrocarbon based fluids have been lost to the formation at high spurt losses during overbalanced operations, or may subsequently be mobilized during high drawdown cleanup or production operations when a portion of the invaded fluid is recovered from the matrix.

External Solids Entrainment. This damage mechanism refers to the invasion of solid particulate material into the matrix surrounding the wellbore or fracture face during overbalanced drilling or completion operations. This mechanism of damage, while significant in higher permeability reservoirs (most notably in cases of open hole completions) is typically a non-issue in very low permeability gas wells, since it is implicit that some type of fracture or other invasive stimulation treatment will be required to obtain economic production rates (the surface inflow area in the unstimulated wellbore is too low to permit economic production rates of gas, even if the well is drilled and completed in a totally undamaged fashion). Since invading solids (particularly in rocks with a matrix composed primarily of micropores where average pore throat aperture is often less than 1 micron in diameter) usually penetrate only a very short distance into the reservoir (less than 10 mm or about 3/8" in most cases), it is understood that shallow, but severe damage may not be an issue, as long as it is highly localized to the near wellbore region and does not cause such severe tortuosity that it is difficult to mechanically propagate the subsequent stimulation treatment. The exception to this statement would be a situation where a horizontal or vertical wellbore is used to penetrate a low permeability gas reservoir where the dominant mechanism of production is drainage of the tight matrix through a natural fracture system. In this case, the well would generally be oriented to have the maximum potential for fracture intersection and mechanical loss of whole mud or solids which may bridge and plug the fractures at the fracture-wellbore intersection, and restrict the ability of the fractures to deliver gas to the formation which may be highly detrimental to the well's performance.
Relative Permeability Effects-Phase Trapping. This issue is one of the most severe that often plagues the success of a low permeability gas reservoir production operation. Since many reservoirs of this type fall into the classification of subnormally saturated or desiccated reservoirs, (as discussed in the preceding sections), there is a tremendous amount of potential capillary pressure energy (capillary suction as it is sometimes referred to) which wants to imbibe and hold a fluid saturation in the porous media. Phase trapping effects can occur in gas reservoirs for both water and hydrocarbon based fluids. In most cases, water is the wetting phase, which tends to reduce or eliminate the affinity for spontaneous imbibition of a hydrocarbon based liquid phase into the matrix surrounding the wellbore (although this fluid may still be displaced into the matrix of the rock by overbalanced drilling and completion procedures, or deposited in place by the depressurization of rich retrograde condensate type reservoir gases).

The basic mechanism of a phase trap in a low permeability gas saturated matrix is illustrated in Fig. 8. It can be observed that the pore system of the reservoir is initially at a low liquid saturation which provides the maximum cross sectional area for flow in the pore system, and therefore the highest level of permeability. If a water-based fluid is introduced into the system (middle frame in Fig. 8), we can see that a high water saturation in the flushed zone is generated and results in some trapped gas saturation. Upon reversal of flow to clean up the well, insufficient capillary drawdown gradient is present to overcome the capillary pressure effects (Fig. 9) which results in a much higher trapped liquid saturation being obtained in the porous media. The configuration of the gas-water relative permeability curves for the porous media will determine the amount of reduction in permeability associated with this increased saturation. Figures 10 and 11 illustrate favorable and unfavorable rock geometries for phase trapping issues with water. In Fig. 10, it is observed that the pore system contains substantial microporosity and that the majority of the effective permeability in this media is contained in a relatively small fraction of the pore space which consists of interconnected meso or macropores or small fractures. In this case, the natural capillary imbibition will draw invaded water into the tightest portions of the pore system on a selective basis. Although these portions of the reservoir can be saturated with water, effective gas permeability may not be significantly altered as the occluded portion of the pore system represents solely ineffective porosity. It is only when the trapped water saturation increases to the point where it is sufficiently large that it begins to encroach into the meso/macropores and significant reductions in permeability to gas are observed. Therefore, rocks of this pore geometry may be significantly less sensitive to water-based phase trapping, as significant increases in the initial “trapped” water saturation can be tolerated without severe accompanying reductions in permeability.

In sharp contrast to this would be a pore system as illustrated in Fig. 11 which is dominated by micropores and a more randomized and uniform pore size distribution. In this situation, even relatively small increases in trapped liquid saturation start to impinge upon the ability of gas to flow within the tight matrix and may result in only a modest increase in initial water saturation causing a large reduction in effective permeability.

Hydrocarbon phase traps may also be problematic in low permeability gas reservoirs. In many situations, no pre-existing liquid hydrocarbon saturation exists in these sediments, and the hydrocarbon fluid is introduced either by the direct displacement of an oil-based completion/stimulation fluid into the reservoir, or deposited directly in place in the matrix due to retrograde condensate dropout effects when a rich gas is produced at a flowing bottomhole pressure less than the dewpoint pressure of the gas. Hydrocarbon phase traps may once again severely reduce the permeability to gas in the pore system, depending on the pore geometry and the wetting characteristics of the gas under consideration. Careful evaluation of the retrograde character of rich gases should be made during the screening process when examining the viability of a low permeability gas reservoir. The presence of a retrograde dewpoint system does not necessarily preclude the economic production of gas from a low permeability reservoir, but will generally degrade the performance character and may require some alterations to the completion and production practices required in order to obtain optimum recovery. More detailed descriptions of the mechanism of phase trapping in low permeability porous media can be found in the literature (Ref. 5).

Glazing and Mashing. Refers to mechanical damage induced by the drill bit or rotating drill string and represents a layer of very thin damage immediately at the wellbore-formation interface. This damage, once again, is of very limited extent and would not be a concern except in an unstimulated open hole completion (which, as previously discussed, would be extremely rare in a low permeability gas reservoir application).

Chemical Formation Damage Mechanisms
Adverse Clay Interactions. Certain clay structures may either be susceptible to hydration by fresh or low salinity water contact (such as smectite or mixed layer clays), or deflocculation or dispersion (kaolinite and other fines) caused by abrupt salinity transitions or caustic pH. In many cases, low permeability gas reservoirs are characterized by compacted, cemented, fine grained matrix and often contain little or no reactive/uncemented clay. Exceptions include dirty sands where the low permeability is motivated by a high concentration of pore filling and occluding clay. Inhibitive water-based or oil-based systems or pure gas systems are sometimes considered for drilling and completion options in these circumstances.

Various Precipitates and Solids. Compatibility of introduced fluids with in-situ formation fluids is always of importance in an effective drilling, completion and stimulation program. Standard compatibility protocols for water-water compatibility, scaling, and water-oil emulsion tests have been defined by the API. In
general, due to the small volume of initial fluid in place in most viable low permeability gas reservoirs, fluid-fluid compatibility issues do not tend to be one of the dominant issues of concern.

**Biological Damage Mechanisms**

These are associated with the introduction of viable bacteria to the formation which may colonize and propagate in either an aerobic or anaerobic fashion. This may create issues with corrosion, souring of reservoir fluids (sulphate-reducing bacteria), or production of viscous polysaccharide bio-slimes which may occlude permeability. Most bacteria cannot thrive at temperatures above 100-110°C which, in deeper tight gas formations, may reduce the severity of this problem. Relatively low water saturations may also hinder the ability of the bacteria to colonize and propagate; however, if large volumes of water-based fluids are lost to the formation during drilling and completion and are permanently retained, this may serve as a breeding ground for viable bacterial populations. More details on bacterial formation damage are provided in the literature (Ref. 10).

**The Tricks!!!**

**Proper Evaluation of Initial Permeability.** Routine or conventional core analysis is a valuable comparative tool for contrasting pay zone quality on a sample to sample basis within a given zone. However, it can be misleading when trying to infer actual in-situ permeability. Permeability data presented in standard core reports have generally not been corrected for overburden compression effects (most analysis are conducted at only a nominal confining pressure of 1380 kPa [200 psi] unless otherwise specified), surface slippage [Klinkenberg effects], clay and mineral hydration effects and relative permeability effects associated with the presence of a trapped water/oil saturation in the reservoir in comparison to the clean, dry core used for the routine core analysis. This can result, particularly in low quality matrix, in the observed routine core analysis gas permeabilities being orders of magnitude higher than the actual effective in-situ permeability to gas (even in totally undamaged conditions). In-situ permeability measurements from pressure transient/buildup tests (in homogeneous unfractured formations), or reservoir condition in-situ permeability measurements on properly handled and restored and stressed core samples are generally the best indication that sufficient undamaged ‘matrix’ permeability is present to facilitate economic gas production rates.

**Proper Evaluation of Initial Fluid Saturations.** Evaluation of initial water saturation in a low permeability gas reservoir is difficult due to the fact that the composition of the formation water in the reservoir and hence, the resistivity of the formation water for water saturation calculation from induction logs, is often unknown. Due to the very low initial water saturation present in the reservoir, mobile formation water is rarely produced from viable low permeability gas reservoirs. The little water that is produced from the wells is generally fresh water of condensation from the gas, and is not reflective of the true in-situ composition of the water contained in the reservoir matrix.

One of the primary mechanisms for the establishment of the low initial water saturation which exists in many low permeability gas reservoirs, as previously discussed, is associated with long term gas migration and gradual evaporation effects that have reduced the initial water saturation in place in the reservoir. This process can be seen to have a concentration effect on the dissolved solids present in solution in the remaining trapped water saturation. For example, assume deposition of the sediments in an initial marine seawater environment with a salinity of approx. 30,000 ppm. If the reservoir is subsequently isolated from free water contact by tectonic or erosional events and desiccation occurs, reducing the water saturation from an average initial value of 50% to 10%, one can see that this will result in a concentration of the soluble salts in the brine into the remaining water saturation (as they will not be extracted into the gas phase with the evaporating water), and that the effective salinity of the remaining brine saturation will increase to 150,000 ppm. This obviously causes a significant reduction in the apparent resistivity of the formation water.

However, if a regional water salinity, or a salinity based on the composition of fresh water of condensation produced at the well is used, the resistivity of this brine will be much higher than is actually present in the reservoir resulting in the prediction of a much higher water saturation than is, in reality, present in the reservoir (using conventional log analysis parameters). This may result in a potentially productive zone being diagnosed as wet and may result in “bypassed” pay as these zones may not be deemed worthy of completion, when, if near wellbore drilling induced damage is penetrated, they may be capable of economic production rates.

In the absence of good Rw data and log calibration parameters, direct measurement of the in-situ water saturation is sometimes attempted. The most common technique used in this area is evaluation from core samples which have been drilled with an pure oil-based system or with some type of traced water based system so that filtrate flushing effects can be backed out of the measured water saturations. Pure gas or air as coring fluids (due to heat and dessication effects) and invert emulsion drilling mudds (due to wettability alterations caused by flushed drilling mud filtrate which may lower the measured water saturation), are not recommended for this procedure.

**Formation Damage issues: How Much Impact Do They Really Have?**

Formation damage during completion operations has already been discussed as a potential source of reduced productivity of a low permeability gas reservoir. Analysis of typical fracture treatments indicates that large treatments can sustain substantial reductions in permeability on the fracture face before causing appreciable reductions in apparent productivity of the fracture treatment. This is due to the very large surface area which is generated with a well designed and executed fracture treatment. In many cases, the ultimate productivity of the fracture treatment
is controlled by the ability of the generated fracture to conduct gas back to the wellbore, rather than the ability of the formation to conduct gas to the fracture.

This stated, some obvious factors still emerge:

1. The larger the generated fracture treatment, the less significant the damage effects on the fracture faces tend to become and the more important it is to maintain effective fracture conductivity. Smaller fracture treatments (i.e., less than 20 tons), become increasingly sensitive to fracture face damage effects as the ratio of inflow area to fracture conductivity area becomes smaller and therefore impacts ultimate flow capacity to a larger extent.

2. The lower the effective “undamaged” permeability of the formation, the more significant the damage effects. The suppressing effect of damage on a fracture treatment is reliant on the ability of the fracture face to supply more gas to the fracture than it can effectively conduct to the wellbore under a given set of drawdown conditions. If fracture face inflow becomes limited by the ability of the formation face to provide fluids to the fracture, rather than by the fractures ability to conduct the fluids, then reductions in productivity will be more significant with increasing damage to the fracture face.

3. Even though the fracture area may be large, if a total 100% reduction in fracture face permeability occurs during completion, due to a damage mechanism such as phase trapping, (which is one of the few damage mechanisms that is capable of causing damage to this extent in very low permeability reservoir matrices), it can be seen that no matter how large the effective frac area, inflow will be compromised and the frac may be ineffective. Therefore, the topic of formation damage and appropriate selection of the proper fracture fluids and technology is of significant import in low permeability gas reservoir situations. These issues are pictorially illustrated as Fig. 12.

**Evaluating If Phase Trapping is a Problem.** A number of different techniques are available for evaluation if phase trapping of water or hydrocarbon based fluids may be an issue for a low permeability gas reservoir. If core material is available, a simple procedure known as a “phase trapping test” is often conducted on samples of representative average to better quality pay at downhole conditions to evaluate the sensitivity of the matrix to both water and hydrocarbon based fluids and ascertain the best techniques for drilling and completion of a given well.

A phase trap test (Ref. 11) uses actual core material restored to proper initial saturation conditions. A baseline series of permeability measurements is conducted over the range of expected drawdown pressures so that turbulent flow effects which may reduce the permeability at high drawdown rates can be accurately distinguished separately from permanent damage effects. This is followed by invasion of the sample with a specified volume of potentially damaging water or oil based filtrate. This procedure is then followed by a series of regain permeability measurements, conducted at the same drawdown levels as the baseline pre-exposure permeabilities, and the damage effect and threshold pressure (drawdown pressure required for the first point of gas mobilization). Table 1 provides a sample set of typical permeability measurements for a low permeability gas reservoir using a water-based 3% KCl completion fluid. The data has been plotted and appears as Fig. 13.

**Imbibition Issues.** Fig. 14 provides an illustration of a set of water-gas capillary pressure curves for a typical low permeability gas reservoir. These curves are typified by a high “threshold pressure” for initial gas intrusion into the water saturated matrix and a high irreducible water saturation. If a reservoir which exhibits this pore geometry is in a subirreducible initial water saturation condition, as illustrated by point “A” in Fig. 14, one can see that there is a large amount of “potential” capillary energy that exists between the natural equilibrium water saturation desired to be present in the rock from a capillary mechanics point of view in comparison to the present water saturation level. In these situations this creates an extremely powerful hydrophilic suction tendency for water (assumed to be the wetting fluid in this example) into the matrix. This means that considerable invasion, due to capillary suction effects, can occur when water based fluids are in contact with the formation, even in the absence of a significant overbalance pressure. A phenomena known as countercurrent capillary imbibition has been well documented in the literature in previous papers and studies by the authors (Ref. 16) and illustrates how a significant increase in water saturation in the near wellbore or fracture face region can occur in such a situation, even if underbalanced operations are being used when water based fluids (including foams), are circulated in contact with the formation face.

Therefore, one can see that proper evaluation of the initial liquid saturation values, capillary pressure and imbibition character, as well as the phase trapping characteristics of the porous media, determined by the specific pore geometry and relative permeability characteristics under consideration, must all be carefully considered in concert to determine the sensitivity of a reservoir to phase trapping concerns.

**Mitigating Phase Trapping Issues in Low Permeability Gas Reservoirs.** Fluid retention may be one of the greatest barriers to the production of low permeability gas reservoirs. Once the operator understands the potential severity of this issue with respect to their particular formation, a number of different approaches can be taken to minimize its impact.

**Avoid Using Trapping Fluids.** If a severe sensitivity to water based phase trapping is present, consideration may be given to using different fluid bases which have less trapping and imbibition affinity. Oil based fluids may be considered in some situations for low perm water wet gas reservoirs. As the nonwetting fluid in this case, there will be no spontaneous capillary imbibition effect to draw these fluids into the reservoir matrix (although they may still be displaced into the reservoir rock due to overbalanced pressure operations). As the non-wetting fluid, if oil-based fluids are lost to the reservoir, they tend to be trapped in the central portion of the pore space, rather than adhering tightly to the matrix walls as the wetting phase.
Although this central pore space occlusion can cause substantial reductions in permeability, in some cases, the total reducing effect is less than if a water based system had been used in the same circumstances, as the total volume of pore system occluded is less. This phenomena is schematically illustrated as Fig. 15. A series of phase trapping tests on representative core material usually can accurately define for a given reservoir if the use of oil based fluids may be advantageous over water based systems in the same situation. Another alternative, if both water and hydrocarbon based systems appear highly damaging from a retention point of view, is to consider the use of highly energized (N₂ or CO₂) system, to increase near wellbore charge energy, reduce IFT and reduce the volume of trapping fluid invading the rock, or pure gas based systems such as pure CO₂ or N₂/CO₂ “foam”.

Reduce Exposure Time and Depth of Invasion and IFT. In many circumstances where large fracture treatments must be propagated, or if reservoir temperatures are very high (or both), current technology is highly weighted towards the use of water based heavy metal cross linked gels. In a situation where it is expected that some degree of water invasion will occur, a prophylactic approach must be taken to:

1. Design fluid rheology and breaker properties such that the minimum amount of leakoff of water based filtrate over the period of high overbalance exposure occurs.
2. That the fluids are removed from formation contact by rapid backflow and cleanup as quickly as possible to reduce static or dynamic capillary countercurrent imbibition effects.
3. Capillary pressure, which is the dominant variable controlling fluid retention, is a direct linear function of interfacial tension between the water and gas phase. If this interfacial tension can be reduced between the invading water based filtrate and the in-situ reservoir gas, the magnitude of the capillary pressure and the degree of observed fluid retention may also be lessened. Common IFT reducing additives to water based fluids would include various volatile alcohols (methanol being the most prevalent), surfactants and liquid or gaseous carbon dioxide. Care must be taken with the use of alcohols and CO₂ when liquid hydrocarbons may be present as a trapped or mobile saturation in the reservoir, as problems with deasphalting (CO₂) or sludging (MeOH) may occur.

Static Exposure Time. Fig. 16 illustrates the situation where a volume of water-based filtrate invades the region surrounding a wellbore or fracture face in a low permeability gas reservoir. In this situation we can see that initially the trapped water saturation is high enough to almost totally occlude the permeability to gas in the near wellbore/frac face region. Nature abhors steep capillary gradients however, and we can see that natural capillary imbibition will want to ‘wick’ or imbibe water from the high water saturation zone (encompassing the original invaded area) deeper into the formation, resulting in a ‘smearing’ of the water saturation profile as illustrated in Fig. 17. As long as a recharge source of unbound water is removed from the wellbore or fracture, this will obviously result in a gradual reduction in the value of the trapped water saturation in the near wellbore or fracture face region, which may result in a slow long term improvement in the permeability to gas in the region which previously exhibited near zero gas permeability. In many cases, a period of static shut in may substantially improve the productivity of a ‘damaged’ gas well. Flowing the well may be counterproductive in such a situation, as this imposes a pressure gradient which opposes the capillary imbibition force which may slow or negate its effect. Also, high drawdown pressure may result in additional water of condensation precipitating from the gas in the high drawdown region adjacent to the wellbore or fracture face, which may add to the already existing trapped water saturation and exacerbate the trapping effect.

Experimental studies of the imbibition process indicate that the process seems to work the best in permeabilities which are somewhat greater than typically observed in low permeability gas reservoirs which are the subject of this paper. In-situ perms in the range of 1-2 mD seem to be the most suited to this technique, as the imbibition effect and improvement in gas perm can be significant in relatively short period of time (few days to few months). As permeability is lowered, although the force of capillary pressure increases, the relative speed of imbibition slows and many years may be required before a substantial effect is observed, which often is not a viable economic option for a stimulation treatment.

Hot and Conventional Dry Gas Injection. The imbibition process may be hastened in some reservoir situations where water based phase trapping is known to be a source of substantial reduced productivity by the injection of dehydrated dry gas into the formation. Due to the suppressed dewpoint of this gas, it may have extractive ability to remove trapped water from the near wellbore or frac face region by dessication effects. The objective of this treatment is to create some paths of low water saturation back to the undamaged portion of the reservoir to initiate conduits of higher gas permeability through the damaged zone. The speed of the process may be hastened in some situations through the application of heat to speed the extractive process. The use of downhole heating tools for this purpose has been documented in the literature (Ref 13, 14). One must be careful that the total dissolved solids content of the trapped brine is not too great if such technology is contemplated, as the desiccation of the in-situ water may result in rapid super saturation of the remaining water saturation with dissolved ions and the subsequent precipitation of halite or other crystalline solids within the pore system which may have an equally damaging effect to the initial water trap which was present. In general, for low permeability porous media, if the value of the TDS in the trapped water saturation exceeds 50,000 ppm, this method should not be considered for use.

Use of IFT Reducing Solvents for Water and Oil Retention Problems. The role of IFT on capillary pressure has already been discussed. As a post damage stimulation treatment, the use of various IFT reducing solvents has long been recognized as a potential means for removing trapped fluid and improving the
productivity of damaged low permeability gas reservoirs. Once again, for water based fluids, IFT reducers such as various soluble volatile alcohols (methanol being the most common for dry gases with no associated hydrocarbon liquids in the formation), or liquid carbon dioxide are the most common. For trapped hydrocarbons, depending on the reservoir conditions and the composition of the trapped hydrocarbon phase, various types of miscible solvents such as carbon dioxide and liquid ethane or propane or lean gas (dry methane) when reservoir pressure is sufficiently high, may be contemplated for use. A wide range of lab tests can be used to evaluate the effectiveness of these treatments to determine the technology best suited for application in a given set of circumstances (Ref. 11).

Inhibitive Base Fluids. If studies suggest concentrations of reactive clays are present, or if fluid-fluid interactions are indicated, a variety of inhibitive based fluids can be evaluated using both computer models and special core analysis techniques to select the fluid base most appropriate for use.

Conclusions
This paper has discussed the criteria for selection and completion of viable low permeability gas reservoirs. This includes:

1. Evaluating if in-situ permeability to gas in an undamaged state is sufficient for gas production under the current reservoir pressure. Typically cutoffs for higher pressure formations tend to be in the 5-10 micro Darcy range (0.005-0.010 mD) and will be greater if subnormally pressured or pressure depleted or shallower, lower pressure reservoirs are under consideration.

2. For a very low permeability (<0.10 mD) gas reservoir to represent potential productive pay in general, we find that the reservoir matrix is undersaturated or desiccated with respect to the initial water saturation. This issue is believed to be due to long term regional gas migration and evaporative effects and contributes to the increased sensitivity of low permeability gas producing formations to fluid retention (phase trapping) as a major damage mechanism occurring during completion operations.

3. Low permeability gas reservoirs can be subject to a number of different damage mechanisms during drilling, completion and production. In general, due to the character of the formations, fluid retention may often be a significant damage mechanism. The impact of fluid retention and trapping are strongly affected by the interaction of pore geometry, wettability, invasion depth, drawdown pressure, capillary pressure and relative permeability and are unique for every reservoir situation. Not all low perm reservoirs may be adversely impacted by phase trapping effects, although it has been documented to be a significant damage mechanism in many cases.

4. A variety of techniques have been presented for both evaluating initial formation permeability and fluid saturations, as well as for determining and reducing the impact of formation damage in various reservoir scenarios.

Nomenclature

- \( P_c \) = Capillary pressure
- \( P_{sw} \) = Pressure in non wetting phase (gas)
- \( P_w \) = Pressure in wetting phase (water/liquid hydrocarbon)
- \( \theta \) = Contact angle between gas and liquid in rock surface
- \( R \) = Pore throat radius
- \( \sigma \) = Interfacial tension between gas and water
- \( g \) = Gravitational constant
- \( h \) = Height above free water contact
- \( \Delta \rho \) = Density difference between gas a liquid
- \( R_1 \) = Primary radius of curvature of gas-liquid interface
- \( R_2 \) = Secondary radius of curvature of gas-liquid interface

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References


Table 1. Typical Regain Permeability Data for Low Permeability Sandstone Reservoirs

<table>
<thead>
<tr>
<th>Drawdown Pressure (kPa)</th>
<th>Permeability to Gas Pre-Exposure to KCl Fluid (mD)</th>
<th>Permeability to Gas Post-Exposure to KCl Fluid (mD)</th>
<th>Percent Change (%)</th>
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Figure 1 - Typical Interfacial Radii of Curvature in Porous Media

Matrix Grains

Non-wetting Phase

Wetting Phase

Figure 2 - Typical Radii of Curvature in Low Permeability Porous Media

Small Radii of Curvature
High Pc and Swirr
Figure 3 - Typical Radii of Curvature in High Permeability Porous Media

Figure 4 - Typical Capillary Pressure Type Curves for Different Permeability Ranges of Typical Intercrystalline Porous Media
Figure 5 - Illustration of Reduction in Gas Phase Permeability as Trapped Water Saturation Increases - Pore Scale

Initial Swi Low - Increased Gas Reserves and Initial Permeability to Gas

Initial Swi High - Reduced Gas Reserves and Initial Permeability to Gas

Figure 6 - Reduction in Effective Permeability to Gas as Swi Increases - Relative Permeability Basis
Figure 8 - Basic Phase Trapping Mechanism for a Low Permeability Gas Reservoir
Figure 9 - Illustration of Capillary Pressure Effects on Phase Trapping

Figure 10 - Favorable Relative Permeability Curves/Rock Geometry Which Minimizes Phase Trapping Concerns
Figure 11 - Unfavorable Relative Permeability and Rock Geometry for Phase Trapping

Figure 12 - Issues Affecting Inflow/Damage in Hydraulically Fractured Wells
Figure 13 - Typical Baseline and Regain Permeability Curves for a Low Permeability Gas Reservoir Exposed to 3% KCL Filtrate

Figure 14 - Typical Capillary Pressure Curves for Undersaturated Water Wet Porous Media Illustrating Imbibition Potential Upon Exposure to Water Based Fluids
Figure 15 - Comparison of Water Based vs Hydrocarbon Based Phase Trapping in a Low Permeability Gas Reservoir

Figure 16 - Illustration of Water Invasion in a Water Wet Low Perm Reservoir - Prior to Time Induced Dispersion
Figure 17 - Illustration of Water Invasion in a Water Wet Low Perm Reservoir - After Time Induced Dispersion