ROCK PROPERTIES AND THEIR EFFECT ON GAS FLOW AND RECOVERY

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INTRODUCTION

Voids within the rock matrix form the container in which gas accumulates; therefore, knowledge of the quantity and distribution of these voids (pore space) is essential in assessing the quantity and distribution of gas present. The shapes, variety of sizes, and distribution of the pore space on a microscopic scale are referred to as pore geometry. This geometry differs widely because of the varying depositional environment of reservoir rocks, and subsequent diagenesis. Pore geometry is related to the quantity and distribution of storage space (porosity), and through capillary forces it influences the reservoir distribution of gas and water.

The ability of a formation to transmit fluids (permeability) is also related to pore geometry. The native ability to flow can be decreased during completion operations by reaction of the rock with the completion fluids. In addition, an increase in effective overburden pressure typically occurs during production, and this also results in decreased flow capacity. Low permeability gas reservoirs are particularly sensitive to both these effects.

The introduction of filtrate into a gas formation reduces gas flow capacity—even when no rock-fluid reaction occurs. This permeability reduction is controlled by relative permeability characteristics of the rock. This loss of flow capacity occurs whether the extraneous liquids are introduced in the zone from filtrate invasion during completion or workover operations, or by retrograde condensation.

Influx of water into a gas reservoir traps a quantity of gas behind the water-gas front. This trapped gas is not recoverable and varies with rock type, and in some cases with permeability and porosity within a given formation. The magnitude of this trapped gas must be known and accounted for in order to estimate gas recoverable reserves in water-drive and gas storage reservoirs.

Gas storage projects serve as accumulators of gas near the area of need. Storage capacity, capillarity, transmissibility, relative permeability characteristics, and trapped gas quantities are necessary in evaluating the potential of the storage zone. In addition, threshold pressure tests are required to evaluate the suitability of the caprock matrix that overlies the storage zone.

QUANTITY AND QUALITY OF PORE VOLUME

Texture

The texture of rocks is important in that it reflects the pore geometry. Common textural properties include the chemical composition of the rock, and in sandstones also include the grain shapes, roundness, sizes and sorting. A uniform grain size generally signifies a high void volume, assuming the pore space has not been filled in with secondary cement. Even in sandstones of uniform grain size, porosities can vary from a theoretical maximum value of 47.6 to as little as 26%, depending upon the packing arrangement. Even in coarse-grained sandstone formations where one expects to find larger pore spaces, the relative size of the pores is small when compared to those found in many carbonates.

Pore volume development in carbonates is much more variable than normally seen in sands. Figure 1 shows a thin section of a reef limestone containing a variety of pore sizes. Thin sections of oolitic limestone show it approaches a coarse-grained sandstone in appearance and rock properties. Classification of carbonate rocks by textural properties is more difficult than classification of sandstones. One approach was that proposed by Archie[1]. The texture of the matrix is assessed by visual examination as to Type I, Type II, or Type III. These types refer to a compact crystalline matrix, chalky matrix, and granular or sucrosic matrix, respectively. In addition, the matrix grain size is reported as well as the sizes of pores present. This classification is often helpful in correlation of measured rock preperties.

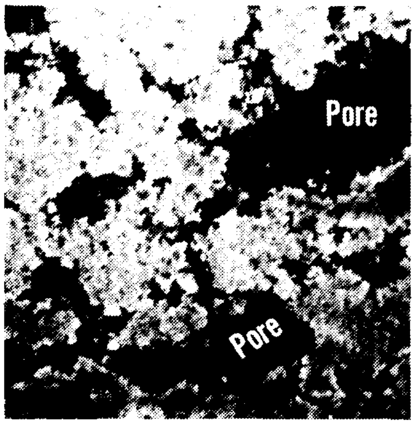

FIG. 1—REEF LIMESTONE PHOTOMICROGRAPH

Clays

Pore volume in sandstones is sometimes reduced by the presence of clays located within the pore space. Common clays present are kaolinite, illite, chlorite, and montmorillonite. In some instances, montmorillonite-type clays have been found in carbonates, although this is not normally the case. Clay causing the most difficulty in reservoir operations is montmorillonite. The clay lattice is not electrically balanced and polar compounds such as water can enter between the clay layers causing plate separation and swelling. This clay, as well as degraded illite and chlorite, causes difficulty in the measurement of pore volume on core samples[2] and reduces reservoir gas flow capacity under certain circumstances.

Overburden Pressure

The weight of the rocks overlying a hydrocarbon reservoir imposes overburden pressure that tends to reduce storage capacity. This overburden pressure is partially supported by internal reservoir pressure which is normally related to the hydrostatic gradient. In cases where gas production is accompanied by reservoir pressure decline, the net overburden pressure (overburden weight minus reservoir pressure) on the formation increases as reservoir pressure declines. This causes a decrease in reservoir pore space. A second consideration concerns measurement of pore volume on rock samples at the surface under zero net overburden conditions, and the corrections that must be applied to reduce these volumes to those existing in the reservoir. Experiments show that well-cemented, elastic rocks do not undergo substantial volume change from their in situ environment to the surface. As rock character changes to the more friable and then to unconsolidated formations, changes in pore space become important[3]. Porosity should be measured on samples of this latter type under a confining pressure approximating the in situ stresses. Figure 2 illustrates the magnitude of porosity reduction as a function of rock compressibility and induration of the samples.

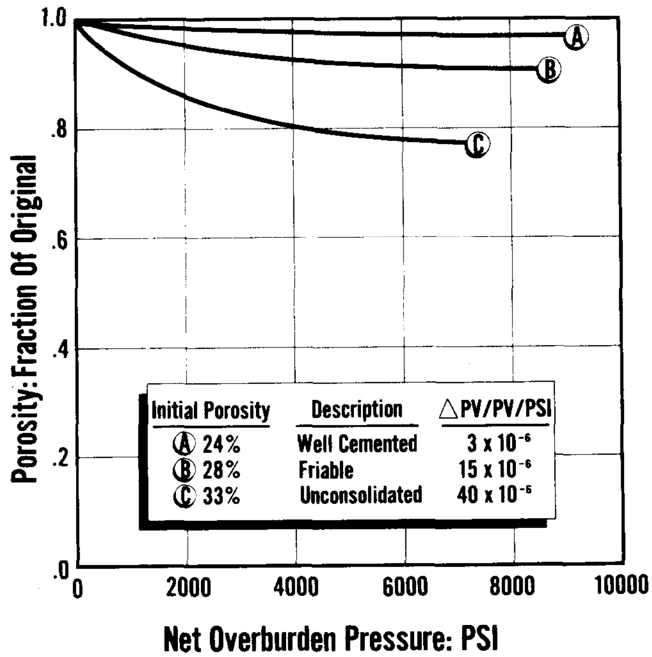

FIG. 2—POROSITY REDUCTION WITH OVERBURDEN PRESSURE

DISTRIBUTION OF GAS IN PLACE

Water is retained in the reservoir by capillary forces as gas accumulates. This water is referred to as interstitial, and in water-wet reservoirs lies next to the sand or carbonate surfaces. These retentive forces are proportional to fluid interfacial tension, the affinity of water for the rock, and inversely proportional to pore size. The smaller the radius of a pore, the larger the capillary pressure and hence

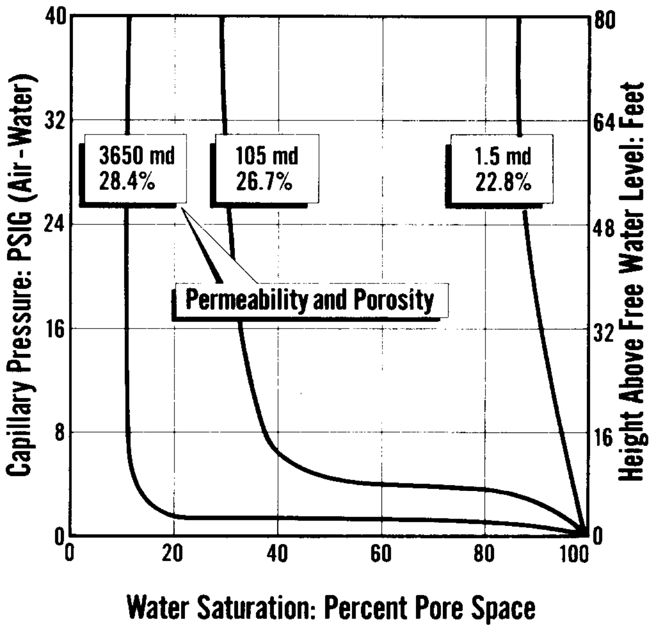

FIG. 3—CAPILLARY PRESSURE CURVES FOR MIOCENE SAND

the retentive force. The implication here is that low permeability gas formations composed of very small pore spaces have high water retentive forces, and hence often contain high water saturations.

Laboratory capillary pressure curves developed on samples from a formation of interest can be used to define water saturation as a function of height above the gas-water contact. Example sandstone curves relating capillary pressure, water saturation and height are shown as a function of permeability on Fig. 3. At a common height, water saturation is shown to be higher in the lower permeability rock resulting in less storage space for hydrocarbons. The relatively large density difference found between water and gas causes a suppression of the gas-water transition zone. This is favorable, and gas reservoirs have smaller transition zones than oil reservoirs in similar type rock.

FLOW CAPACITY OF GAS RESERVOIRS

Gas Slippage

Flow capacity of gas reservoirs is controlled by the size, shape and distribution of the pore sizes within the rock matrix. Permeability is a measure of the flow capacity of a formation. It is a rock property and is normally assumed to be invariant with the pressure differential causing flow. This is not true when highly compressible fluids such as gas are moving through the reservoir or through core samples tested in a laboratory. As the mean pressure in a core sample increases, the gas molecules are compressed closer together resulting in a lower measured permeability. This "slippage" or "Klinkenberg" effect is illustrated on Fig. 4. The minimum value of permeability at infinite mean pressure shown for any given overburden pressure is called "Equivalent Liquid Permeability". It more closely represents in situ flow capacity than values determined at low mean pressures.

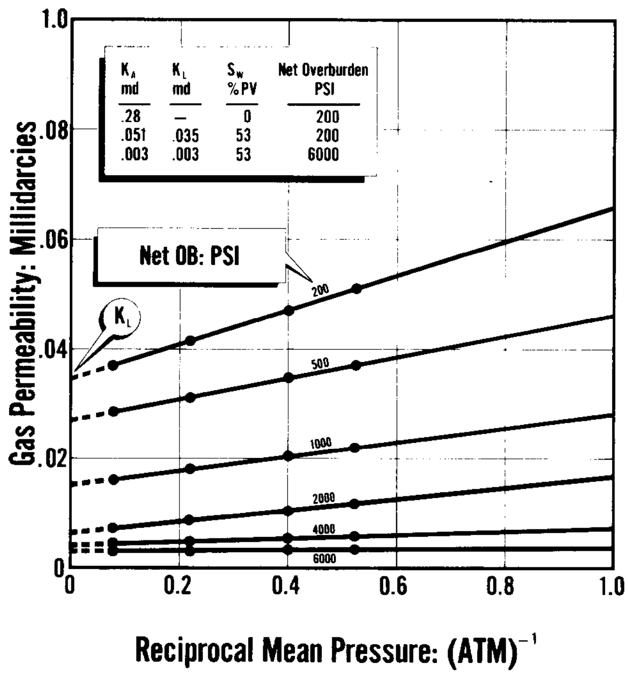

FIG. 4—PERMEABILITY REDUCTION DUE TO GAS SLIPPAGE, IRREDUCIBLE WATER AND OVERBURDEN PRESSURE

Turbulent Flow

Turbulence can occur both in laboratory samples and in gas reservoirs near the wellbore. The effect of this turbulence is shown by Fig. 5. It results in a measured laboratory permeability lower than actual and yields reduced formation deliverability. Equations[4] exist to account for this turbulence in reservoir calculations, and precautions are taken in laboratory measurements to assure that a condition of laminar flow exists at the time of permeability determination.

Clay-Water Reaction

A reaction between water introduced into the formation and clays present in the pore spaces

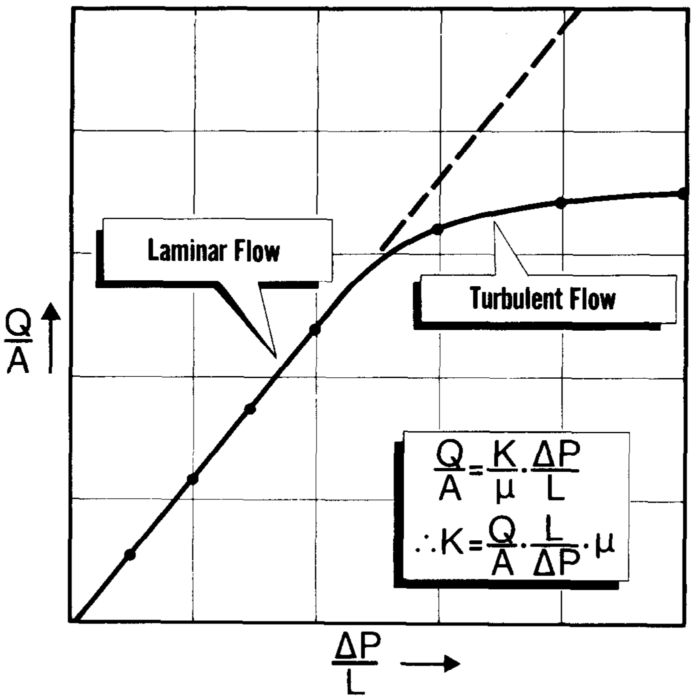

FIG. 5—EFFECT OF TURBULENT FLOW ON PERMEABILITY

results in a reduction in permeability as illustrated on Fig. 6. Factors that influence this permeability reduction include the kind of clay present, its amount and distribution. The presence of montmorillonite is cause for concern, and it typically exhibits the greatest sensitivity to a noncompatible water. An increase in clay quantity and a distribution where clay lines the pore walls are both detrimental. Low salinity water results in maximum clay hydration and maximum permeability reduction. The water composition is extremely important, and the presence of divalent cations such as calcium and magnesium often reduces the sensitivity of the clays to water[5]. The sequence in which the fluids contact the clays also influences clay hydration, and any laboratory test made to evaluate this phenomenon should follow the same sequence as expected in the reservoir operations. In cases where montmorillonite or other swelling clays are not present, kaolinite may cause permeability reduction as particles of clay flake off and move, plugging pore necks. Although the mechanism is different, both clay swelling and particle movement result in reduced flow capacity. These problems can be eliminated in many cases by selection of a water compatible with the clays when such a selection exists, or by adding calcium, magnesium or potassium to the proposed completion or workover fluid. The complexities of the clay structure make prediction of a suitable additive almost impossible, and tests are normally made on samples from the reservoir to find a suitable brine.

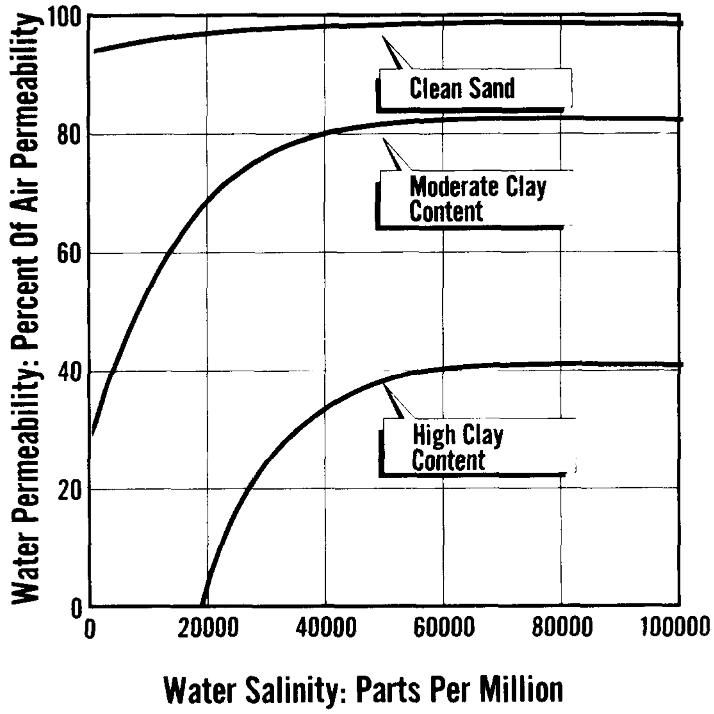

FIG. 6—VARIATION IN WATER PERMEABILITY WITH SALINITY & CLAY CONTENT

Fractures

Native fractures present in formations normally contribute little to porosity but have a pronounced effect on permeability. The presence of fractures results in high productivity reservoirs even when matrix reservoir properties are poor. Where natural fractures do not occur, the productivity of low capacity gas wells has been greatly improved in many cases by fracture stimulation. At times, flow capacity does not improve as anticipated. This lack of improvement is sometimes related to clay swelling caused by reaction of clays with fracture fluids, or a relative permeability effect to be discussed later.

Connate Water Effect in Low Permeability Formations

Estimations of well potentials are made from permeabilities measured on core samples. It has been observed in low permeability gas wells that the potentials estimated from laboratory gas permeability measurements on dry cores may exceed those actually proven under test conditions. This appears to be related to at least two parameters as illustrated on Fig. 4. This low permeability sample contains a water saturation approximating 50 percent pore space. Inclusion of this water results in a permeability equal to 20% of the dry core value.

Overburden Pressure Effect

Figure 4 also indicates the decrease in gas permeability as effective overburden pressure increases. This effect is also important in unconsolidated rocks[3]. This pressure should be accounted for in laboratory permeability measurements and in reservoir calculations[6]. As reservoir pressure decreases with production and net overburden increases, a reduction in flow capability is to be expected.

RELATIVE PERMEABILITY EFFECTS ON FLOW CAPACITY

Relative permeability is a dimensionless term that has importance when more than a single fluid is moving through the reservoir; for example, gas and water. Specific permeability is permeability present with one fluid at 100% saturation, and effective permeability defines the resulting permeability to each phase when a second or third phase is introduced. The ratio of effective to specific permeability defines relative permeability values as a function of saturation. Figure 7 illustrates gas and water relative permeability curves for a gas-water reservoir.

Drainage curves apply during the time water is draining from the reservoir and hydrocarbons are accumulating. Once a sample has attained an irreducible water saturation value and this water is subsequently increased by natural water influx or introduction of coring fluids, a different set of relative permeability characteristics exists. These latter are called imbibition curves. In strongly water-wet reservoirs, it has been observed that the relative permeability to water is essentially independent of the direction of saturation change. This is not true of the gas phase, however, and as water saturation increases, relative permeability to gas is lower than that observed during the drainage process. These data are required in many reservoir engineering calculations, and the laboratory tests that develop these data should follow the same saturation history as that in the

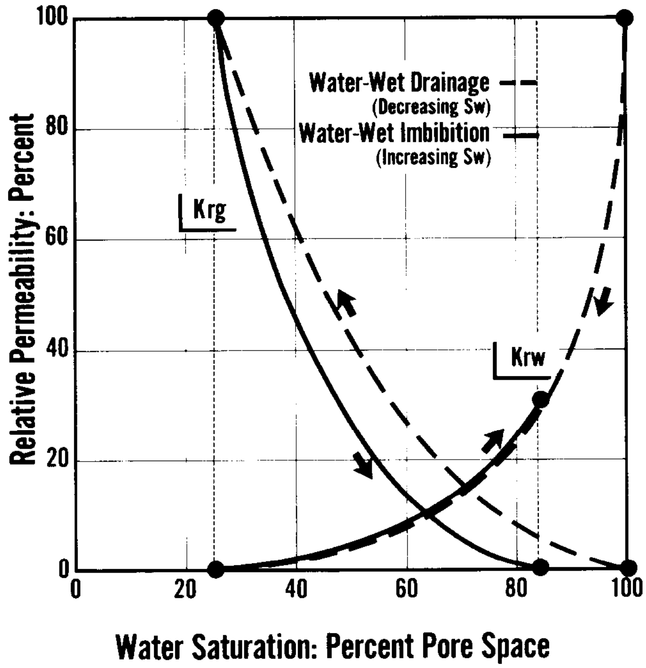

FIG. 7—TYPICAL GAS AND WATER RELATIVE PERMEABILITY CURVES

reservoir. Drainage curves such as these apply both in the accumulation of naturally occurring gas reservoirs and in creation of gas bubbles in aquifer gas storage projects. At the time water influx occurs in a natural gas reservoir or the storage zone gas bubble shrinks, imbibition flow characteristics apply.

The imbibition curves indicate the loss of gas permeability, and hence well productivity expected when water saturation is increased in the vicinity of the wellbore during coring, completion or workover operations. Removal of this extraneous water by production restores productivity if clays have not been hydrated. In many cases, particularly in low permeability reservoirs, water introduced is held by the strong water-retentive capillary properties and is virtually impossible to remove. This relative permeability effect accounts for the abnormally low production rates often seen during a well's cleanup period. In some cases, it takes months to produce the extraneous water held within the pore spaces and to reach production rates that were present prior to the time a well was worked over.

Relative permeability effects are sometimes the cause when expected increases in well productivities do not occur after fracture stimulation. In the event the fracture fluid is imbibed into the rock matrix adjacent to the fracture, transmissibility of the fluid into the fracture can be reduced essentially to zero. To alleviate this effect, exotic fracturing fluids have been devised that vaporize as the fracture fluid temperature rises to that of the reservoir. This vaporization process effectively removes the liquid and reduces permeability reduction caused by relative permeability phenomenon.

In gas condensate wells, relative permeability effects may also reduce flow capacity. This occurs when retrograde condensation within the pore spaces builds up a liquid saturation that interferes with the flow of gas. Above some critical saturation, this liquid hydrocarbon is mobile and migrates toward the producing wellbore. This increase in liquid saturation in the vicinity of the wellbore causes a further deliverability deterioration. In certain low permeability rocks, it has been observed that as little as 15% extraneous liquid reduces the gas relative permeability to a value of approximately 10% of original.

GAS TRAPPED BEHIND ENCROACHING WATER

Water movement into a gas reservoir results in entrapment of a quantity of the initial gas in place. This quantity of gas varies as a function of initial gas saturation and consequently is of smaller magnitude within the gas-water transition zone. As water encroaches into rock which is located above the transition zone and which contains irreducible water, maximum trapped gas exists. Data[7] indicate trapped gas saturations as low as 16% in unconsolidated sandstones and up to 38% in consolidated sandstones. This range of trapped gas saturations has also been observed on tests made in-house; and, in addition, a correlation of increasing trapped gas with decreasing porosity has been observed within certain formations. Results of a study on carbonates made to define trapped gas as a function of porosity and rock type are shown on Fig. 8[8]. The rock classification used here is that of Archie and indicates that fine-grained chalky material (Type II) exhibits much lower trapped gas saturation that that found in irregular pore geometry reef limestones (Type I). The latter show trapped gas values as high as 68% of pore space in samples containing 80% initial gas saturation. Sucrosic material (Type III) falls within the other and also trends with porosity.

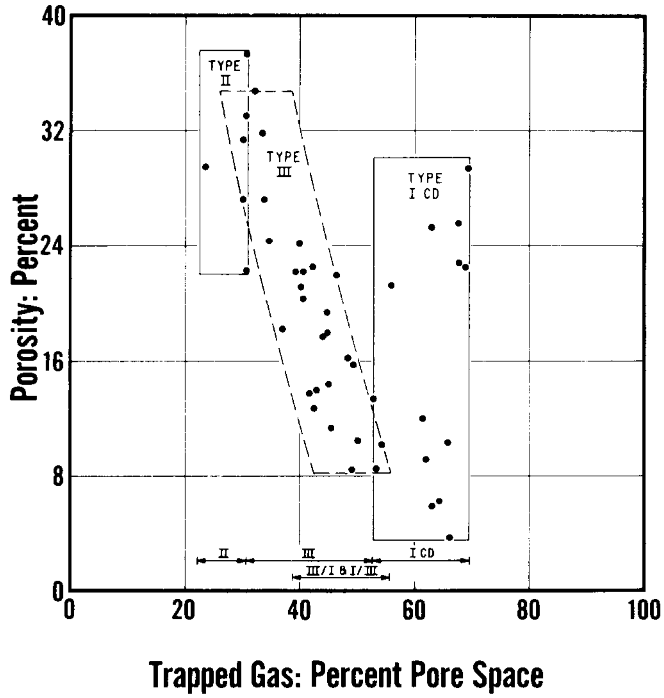

FIG. 8—TRAPPED GAS VERSUS CARBONATE ROCK TYPE AND POROSITY

EVALUATION FOR GAS STORAGE PROJECTS

Evaluation of the gas storage zone in an aquifer gas storage project requires determination of the porosity and permeability of the zone, overburden and relative permeability properties, as well as capillary properties and gas trapped behind encroaching water. In addition, the quality of the caprock overlying the storage zone must be satisfactory to prevent migration of gas upward and out of the storage reservoir.

Certain rock properties control the suitability of the caprock as a sealing medium. These include the permeability of the matrix, which is determined by flowing water through a 100% saturated caprock sample. Permeabilities in the range of 1×10^{-5} and 1×10^{-6} millidarcies have been observed for good caprock material.

It is important to know the pressure at which gas within the reservoir will penetrate the water-saturated caprock. Until this threshold pressure is reached, the capillary retentive forces in the small caprock pores prevent movement of the water and invasion by gas. Once the reservoir gas pressure exceeds the threshold pressure of the caprock, gas will move into and through the matrix. This can be evaluated in a laboratory test by subjecting a water-saturated caprock to the presence of gas under a driving pressure. This gas-driving pressure can be increased in increments until the threshold pressure of the caprock is exceeded. At this point, a measurable flow of water will be observed on the downstream end of the caprock and will continue until gas is produced.

The least expensive way to increase gas storage capacity in a given reservoir is to increase the gas pressure above the original hydrostatic pressure. It is important that a normal fracture gradient of approximately 1 psi/ft of depth not be exceeded during this pressure increase or the caprock may be fractured. As long as the threshold pressure of the caprock exceeds the pressure difference between the original hydrostatic and the fracture pressure, no difficulty would be expected from gas breakthrough into the caprock. It should be recognized that even though matrix properties may be satisfactory, leaks in the caprock may occur because of joints or fractures.

SUMMARY

Gas reservoir rock properties vary widely, and this is reflected in storage capacity, flow capacity and gas recovery. Capillary characteristics of the rock result in higher water saturation retention in the pore space of low permeability formations. The relatively large density difference between gas and water is favorable and tends to reduce the height of the gas-water transition zone.

Gas slippage effects and turbulence can occur in both laboratory and reservoir gas flow. In addition, the presence of certain clays results in a water-rock reaction that reduces permeability to gas. Native fractures increase flow rates dramatically, whereas overburden effects tend to decrease both porosity and permeability. Significant porosity reduction normally occurs only in unconsolidated sandstones, whereas overburden will reduce permeability significantly in both unconsolidated as well as low permeability rocks.

Relative permeability effects have an important influence on flow capacity and explain loss in gas productivity caused when extraneous fluid is introduced into a gas reservoir. In addition, influx of water results in a signigicant entrapment of gas in both gas storage zones and naturally occurring gas reservoirs. Liquid permeability and threshold pressure tests are used to evaluate matrix properties of caprock, and hence its suitability as a sealing medium.

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