Introduction: Basic Well Completion Concepts

Porosity

Porosity is the fraction of the total volume of the rock that is pore (non rock) space or void and not made of solid pieces of the formation. It will be filled with a gas, water or hydrocarbon or two or more at the same time. Porosity will range from a high of 40-50% in some marginally consolidated chalk formations to a low of near zero in some of the evaporites (anhydrite). The average porosity of producing reservoirs ranges from about 5-15% in limestones or dolomites, 10-25% in sandstones and over 30% in many of the chalk formations. In most unconsolidated formation, porosity depends upon the grain size distribution; not on the absolute size of the grain itself. Porosity can be in the order of 35-40% if all grains are close to the same size, but in most cases where a wide range of grain sizes are available, the porosity will be between 15-25%. Severe cases of formations with mixtures of large and very small grains may have porosities less than 15%.

Lower porosities, such as 10% or less, are usually the result of chemical modification of the pore structure, i.e., recementation, precipitation of additional minerals, or leaching and reprecipitation. In some cases, the very consolidated sandstones with overgrowth of quartz may have porosities down to near zero.

Geologists further subdivide porosity into several descriptive classifications that help engineers describe the flow of fluids through the formation and into the wellbore. The major classifications are briefly described in the following paragraphs.

1. Matrix porosity or intergranular porosity - the porosity between the grains of the formation.

2. Vug porosity - porosity in the solution chambers that may range from a tenth of a millimeter to voids larger than a basketball.

3. Fracture porosity - the void space created within the walls of an open natural fracture.

4. Micro porosity - the voids between the clay platelets or particles. Although a large micro porosity may exist, production of fluids from them is often difficult since the fluids are usually held by strong cohesive forces.

The matrix porosity is referred to as the primary porosity and most other porosities are secondary. Usually, the pore space described by natural fractures and vugs are produced or swept very early (flush production) and their continuing use becomes as a conductive pathway to the wellbore. Long term production rate estimates are usually based upon the reserves in the matrix except in very large fields where solution porosity (vugs) is very extensive.

Porosity values derived from neutron or sonic logs are usually used alone with other log information and well observations to establish whether a section of rock is "pay." Although the use of porosity in this manner is common, it can also be very misleading. Obviously, porosity is not a "stand along" value for establishing the quality of "pay." Shales, for example, have porosities of 30% or more but lack the conductive pathways (permeability) to make them economic except where fractured gas-rich shales exist in massive sections.

The location and type of porosity has a great affect on the performance of a well. Relying totally on a log derived porosity, especially in a carbonate, may provide unexpected low production or may result in missing productive intervals. The occurrence of lime muds, a low porosity deposit common within limestones may isolate porosity and result in much lower effective porosities than reported with a log. Fossils, porosity within grains, and isolated vugs encased by grain overgrowths may also result in high porosity readings without adding to the porosity of the reservoir. These porosity problems are usually only spotted with the aide of core examinations.

Lower porosity rocks (less than 10%) may be pay in a few instances if microfractures exist at reservoir conditions. The open microfractures serve as drainage paths for fluid flow from very low porosity but extensive parts of the rock.

Saturation

The fraction of pore space containing water is called the water saturation and usually denoted by an S_w. The remaining fraction of the pore space that contains oil or gas is called hydrocarbon saturation S_h. The simple balance $S_h = 1 - S_w$ accounts for all of the pore space within a rock. In almost every porous formation, there is at least a small amount of water saturation. Usually when the sediments were laid down, the matrix materials were dispersed in water. As the hydrocarbon entered the porous formation, water was displaced from many of the pores, although the displacement process is not efficient enough to move all the water. This displacement process, whether it was oil displacing water over geologic time, or water displacing oil during water drive or water flooding, results in a lower saturation of the fluid being displaced. If a very large amount of the driving fluid is displaced, the quantity of the initial fluid reaches a point, usually a few percent of the pore space, where it cannot be reduced further. This level of fluid is the irreducible saturation of that fluid. Therefore, an irreducible water saturation, S_{wi}, is the saturation of water in the core that cannot be removed by migration of hydrocarbon. This water or oil, S_{oi}, may be trapped in the small pores, held by high capillary attraction, or bound to clays as a surface layer or in the clay lattice.

Permeability

Permeability, denoted by a lower case *k,* is a measure of the conductance of the formation to flow of a fluid. The higher the permeability, the easier it is (takes less driving pressure) for a fluid to flow through the rock matrix. The "law" was originally derived by a French engineer named d'Arcy to account for the flow of water through sand filters. The original permeability concept used darcies as a unit of measurement, but most productive formations will be between 0.001 md (1 md = 0.001 darcy) and 1000 millidarcies (1 darcy). Permeability depends on the absolute grain size of the rock, how well the sediments are sorted, presence of fractures, and how much chemical modification has occurred in the matrix. Flowing and bound fluid properties also affect the permeability. Large-grained sediments with a minimum of fine particles (large, open pores) usually have high permeabilities whereas very fine-grained sediments with small pores have lower permeabilities. Porosity does not always relate directly to permeability. Materials such as shales and some chalks may have very high porosities but low permeability because of lack of effective connection of the pores.

Permeability to oil, water and gas may be different because of viscosity differences and other influences such as wetting and the issue of the thickness of the liquid coating on the pore wall. Oil wet formations are usually thought to be less permeable to the flow of water than water wet formations because the molecular thickness of the oil coating is thicker than that of water. This leaves less pore space for fluids flow. When more than one phase exists in the pore, relative permeability relationships govern the flow.

Relative Permeability

The effects of relative permeability explain many of the problems involved in formation damage and reduction of flow from a formation, either on initial production or after treating with a material which severely oil wets the formation. As will be pointed out in the chapter on formation damage, problems with relative permeability include a significant drop in permeability to the saturating fluid as trace amounts of a second, immiscible phase are introduced in the flowing liquid. Reductions of up to 80% of initial permeability are common when saturation of an immiscible phase is increased from zero to approximately 20 or 25%. It is this significant reduction in permeability that explains much of the damage behind overtreatment with an oil-filming chemical, such as an oil-based drilling mud, or the use of highly absorptive surfactants or solvents. The surface of the rock also plays an important part since the charge of a surfactant controls the attraction to a particular formation face. It must be remembered that severe wettability problems such as the absorption of cationic materials onto sandstones and the absorption of anionic materials onto limestones can play a significant role in permeability reduction.

The reduction from this coating or wetting may be severe and can be long-lasting, depending on the tenacity of the coating.

Matrix cleanup of this type of wetting is imperative to fully restore the flow capacity of the formation. Cleanup of this type of damage must take into account both the stripping of the relative permeability influencing layer and the type of rock surface to which it is adsorbed.

Natural Fractures

Natural fractures are breaks in the fabric of the rock caused by a wide variety of earth forces. These natural fractures may have widths of a few thousandths of an inch to a tenth of an inch or more. Natural fractures generally have a common direction that corresponds to forces generated by a significant geologic event in the area such as folding, faulting, or tectonic forces. Where solution etching or cementation forces are active, the fractures may be widened into extensive vugs with permeabilities of hundreds of darcies or filled completely with precipitated minerals. Stylolites or gouge filled fractures are examples of these behaviors. Natural fractures influence flush production or high initial production rate that diminishes quickly after bringing on a new well or the start of flow in a well that has been shut-in. Although they serve as conductive pathways for oil or gas production, they also will transmit water at a much faster rate than the formation matrix, leading to early breakthrough of water or other type floods and sweep problems in reservoir engineering.

Reservoir Pressure

The pressure that the reservoir fluids exert on the well at the pay zone is the reservoir pressure. In single pay completions with little or no rat hole (extra hole below the pay), the reservoir pressure is the bottom hole pressure, BMP. The initial reservoir pressure is the pressure at the time of discovery. Flowing bottom hole pressure is pressure exerted as the result of a drawdown (differential pressure produced by flowing the well). Shut-in pressure is the stable pressure reached after the well has been shut in long enough to come to equilibrium. Shut-in pressures are often quoted as a function of time.

The initial pressure is usually a function of depth of burial but may be modified by other forces at the time of burial or at a later time. Driving pressure may be supplied by a number of mechanisms depending upon the characteristics of the oil and the surrounding geologic and physical forces. The general types of reservoir drive forces (to the limit of general interest in well completions) are:

1. Solution gas drive - a volumetric displacement where all the driving energy or pressure is supplied by gas expansion as the pressure is reduced and the gas comes out of solution. In reservoirs "above the bubble point", all the gas is dissolved in the oil and there is no free gas. In these reservoirs, there may be a volume change of the oil as the pressure drops and gas breaks out of solution. Reservoir pressure decreases with fluid withdrawals.

2. Gas Cap - a volumetric displacement where the oil is "below the bubble point", i.e., there is free gas or gas saturation in the pores and there may be a gas cap. Reservoir pressure decreases with fluid withdrawals.

3. Water drive - water influx into the reservoir from edge, bottom or water injection wells can provide very consistent drive pressure to a reservoir. Like the oil, the water moves through the most permeable pathways of the formation towards the pressure drop produced by removal of fluids. The water pushes part of the oil in front, entering some of the pores and displacing the oil. Oil production continues long after the breakthrough of water at the producing well since the formation may contain a number of streaks that have permeability differences an order of magnitude or more. Reservoir pressure may remain the same or drop with fluid withdrawals, depending upon how fast the incoming water replaces the withdrawn fluids.

4. Reservoir compression through compaction in poorly consolidated, high porosity reservoirs is also a "method" of supplying driving energy but it usually generates serious problems in the reservoir. In these reservoirs, which may often be initially over pressured, the reservoir fluids are a

overburden load supporting element. Withdrawal of the fluids requires the matrix of the formation to support more of the load from the overlying sediments (overburden). In some poorly consolidated or weak formations, the matrix compresses under the load, leading to lower porosity and a continued pressure on the remaining fluids. Although this is a definite form of pressure maintenance, when the porosity is decreased, the permeability also is reduced. Compaction of the pay in massive sections may also lead to subsidence of several feet at the surface - a critical problem for some offshore rigs and sea level land fields.

5. Pressure maintenance or sweep projects using water or gas are our methods of increasing recovery. These processes come with many of the same advantages and limitations as their natural counterparts.

Pressures

To a workover engineer, pressure can be a powerful tool or a nightmare. The difference is in how pressure control is handled. The following "short list" of pressures and pressure related terms presents an idea of what and how pressures are important to the workover.

1. Reservoir Pore Pressure - The pressure of the reservoir fluids, often expressed as a gradient in psi/ft. The initial reservoir pressure is the pressure at the time of discovery. Fluid withdrawals from a reservoir are made by lowering the pressure in the wellbore. The flow of fluids toward the low pressure creates zones of lower pressure or pressure gradients extending into the reservoir. The reservoir pressure can only be measured at the wellbore in a new well or in a well that has experienced complete buildup.

2. Flowing Bottom Hole Pressure - This pressure is measured at the productive zone during flow. A value of flowing bottom hole pressure is usually reported with a flow rate or a choke setting. A change in the flow rate will change the flowing bottom hole pressure.

3. Drawdown - Drawdown is the pressure differential set by the difference of the reservoir pressure and the flowing bottom hole pressure.

4. Flowing Tubing Pressure - A surface measurement of the pressure in the tubing, prior to the choke, at a particular flow rate. It is equal to the flowing bottom hole pressure minus the hydrostatic pressure exerted by the fluids in the tubing. Because of entrained gas production and gas breakout as the well is produced, it is rarely possible on liquid/gas producers to accurately calculate the flowing bottom hole pressure from the flowing wellhead pressure. Only when the composition of the fluid in the tubing is known can the down hole pressure be calculated.

5. Shut-in Surface Pressure - Any pressure measured at the surface immediately after a well is shut-in will change as bottom hole pressure builds up toward reservoir pressure and the fluids in the tubing come to an equilibrium. Surface measured shut-in pressures are useful in some buildup tests to assess the productivity of a well.

6. Productivity Index - The productivity index is a measurement of well flow potential. It is a term generated from a delivery plot of flow rate and pressure from a particular well. It is commonly expressed as a potential flow rate per pressure drop such as barrels per day per psi. By multiplying the PI by the intended drawdown, a flow rate of the well can be predicted. The PI is established by test on the well. It changes with time.

7. Fracture Breakdown Pressure - A measurement of what pressure is required to hydraulically fracture the rock. The breakdown pressure is usually attained from drilling data, breakdown tests, or fracture stimulations. It is usually expressed as a gradient of pressure per unit of formation depth such as psi/ft.

8. Fracture Extension Pressure - The pressure necessary to extend the fracture after initiation. Like fracture breakdown pressure, it is relevant to a particular well or field.

9. Friction Pressure - When fluids are flowed at high rates through a conduit, there is a resistance to flow caused, at least partly, by friction of the fluids at the boundaries of the conduit and by turbulence (mixing) of the fluids. Whether the conduit is pipe or a fracture, friction represents a back pressure. Friction is expressed as pressure at a rate for a unit length of a particular conduit.

10. Bubble Point Pressure - In a reservoir that contains an undersaturated oil, there will be no gas cap. As the pressure is drawn down, the solution gas will break out of solution. Because of relative permeability and saturation concerns, the occurrence of reaching the bubble point usually coincides with a drop in production.

Pressure Differential

Pressure differential is probably the most important pressure during drilling, completion, workover and production. The differential pressure between the wellbore and the formation dictates which direction fluids will move and at what rate they will move. Additional controls such as reservoir permeability and native and injected fluid viscosity also have an affect, as does the presence of solids in the wellbore fluid when the pressure differential is toward the formation.

In general, drilling pressure differential should be as low as possible to minimize formation damage and the amount of fluid invasion from wellbore fluids. However, during any drilling, completion or work-over operation, the pressure differential must be toward the wellbore (higher pressure in the wellbore than in the reservoir) when well flow is not wanted. Maintaining pressure differential is the same as maintaining well control. Certain conditions, such as intentional or accidental swabbing caused by swab cups or large-diameter tools, can create low pressures at the bottomhole, even with a column of high pressure fluid above the swab or tool. It is the rate of movement and the diameter difference between the object in the hole and the inside of the hole itself that determine the swab or underbalance loads. Each step of a drilling, completion or workover operation, particularly when tools or equipment are removed from the hole, should be examined to determine if swab loads can unbalance the pressure differential and swab fluids into the wellbore.

During production, pressure differential toward the wellbore is essential for fluid flow. Columns of standing liquids, excessive backpressures or large amounts of solids in the fluids in the wellbore will act as a check valve, severely limiting production flow into the well.

The study of pressure differential and pressure drop is commonly done using a nodal analysis program. These programs compute pressure drops and backpressures on a system, and help identify those points that may be bottlenecks to good production practices. There are many instances of wells, some even with large-diameter tubing where the tubing has been found to be a "choke" on the production from the well. Changing out the tubing to a larger size in many cases has doubled production from a high capacity well.

Well Temperature

The reservoir at static conditions has a shut-in or reservoir temperature that is characteristic of the depth times the geothermal gradient for that area. A 13,000 ft deep reservoir in one part of the world may have a bottom hole temperature of 160°F, while a similar depth reservoir in a hotter geothermal area may be 360°F.

As the well flows, the bottom hole temperature will drop depending on the type and amount of gas and the pressure drop. The cooling is produced by the expansion of gas. Temperature reductions low enough to freeze water may form ice or "hydrates" in some gas wells while wells with a smaller ratio of gas to liquids will flow hot to surface.

Fluid Properties

The composition of the fluid in the formation, at various points in the tubing and at the surface have major affects on the performance of the well and the selection of production equipment. The following terms are required knowledge to describe the fluid and their changing nature.

1. Gas-oil-ratio, GOR, the amount of free gas associated with the oil production. The gas may ordinarily be in solution or free gas as in a reservoir with a gas cap. When the gas volume is expressed as a function of the total liquids, the value is the gas-liquid-ratio, GLR. Wells with GLRs above 8000 are considered gas wells, while those with a GOR less than 2000 are labeled oil wells. The wells in between 2000 and 8000 are combination wells. The actual GOR value is usually measured at the surface, its value downhole changes with pressure.

2. Water-oil-ratio, WOR, is the amount of water being produced in ratio to the oil production.

3. Bubble point refers to the pressure that a free gas phase will form in an undersaturated oil. The significance is the addition of another phase that, most likely, will lower the relative permeability.

4. Dew point is the pressure and temperature at which the light hydrocarbon gases, C_3-C_7, begin to condense into a liquid. The addition of another phase will lower relative permeability.

5. Cloud point is the temperature in an oil system where paraffin crystals appear (C_{18} + fraction begins to solidify).

6. Pour point is the temperature below which the oil will no longer pour.

High Temperature and High Pressure Wells

Wells with pressures over 0.6 psi/ft and temperatures over 300°F are often referred to as HTHP wells or high temperature, high pressure wells. These wells account for less than 1% of the total wells drilled, but may cost 5% or more of the total expenditures for drilling and completions. The risk, reward and cost can all be very great in these types of wells. Very special workover and completion operations are necessary to adequately complete and produce these wells.