FORMATION DAMAGE AND MEANS OF PREVENTION USING WORKOVER AND COMPLETION FLUIDS

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Sedimentary formations are the usual target for oil and gas exploration. Of the many classifications of these zones, carbonate and clastic deposits most often bear hydrocarbons in commercial quantities.

Clastic formations are composed of broken and fragmented pieces of older existing rocks. Sands or sandstones can be classified as clastics. They result from erosion and weathering of land masses. The eroded particles are transported by various means to an area of deposition where they are laid down in somewhat orderly strata.

Carbonate rocks result from the precipitation of minerals held within an aquatic environment. Carbonates are formed of varying concentrations of calcium and magnesium carbonates.

Most texts represent sedimentary rocks as orderly strata arranged in uniform distribution. It is very important to remember these zones are actually composed of numerous individual grains of fundamental makeup materials. The size, shape and homogeneity of the matrix greatly contribute to a formation's ability to store and later transmit hydrocarbons. For the purpose of this discussion, any change in the potential for production caused by foreign fluid exposure will be classified as formation damage.

There are four primary formation damaging mechanisms commonly recognized in most sedimentary hydrocarbon bearing zones. These mechanisms are (1) the hydration and swelling of formation clays, (2) the invasion and/or migration of solids into and within the formation, (3) the formation of water blocks, and (4) the formation of emulsion blocks. The damage resulting from any one of these sources can be seriously detrimental to well productivity as well as extremely long lasting. The prevention of these types of damage is much less involved than rectification after damage has occurred.

Formation damage attributable to the four primary damage mechanisms usually results from two sources: filtrate invasion from a drilling or workover/completion fluid system, and the accompanying invasion and migration of solids. The damaging solids may come directly from the fluid system or from the formation itself.

The control of subsurface pressure requires a positive differential pressure be applied toward the formation. This counterbalance pressure forces the loss of the continuous phase from the fluid system. The loss of this filtrate can cause problems involving water and emulsion blockage and also may lead to changes in the formation clays. Any alteration of existing clay structure can severely alter the available flow area within a formation pore throat.

The clays most commonly associated with formation productivity impairment are smectite, illite, kaolinite, chlorite, and mixed layer. Clays laid down with the original formation components generally are not a problem. These clays are tied up within the matrix material and are not available for stimulation from external sources. A clay must be exposed within the flow channel in order to cause damage. Diagenetic clays resulting from secondary formation from available minerals found in most formation waters are the cause of the majority of the damage associated with clay minerals.

Smectite is considered to be the most potentially damaging of the clay group. This clay will hydrate and swell in the presence of most invading waters. The swelling of the smectite particle reduces the radius of flow of the pore in which it is located and facilitates the migration of the particle by weakening the internal bond strength holding the particle together.

Illite and kaolinite, while considered to be nonswelling, are hydratable and contribute to the migration of fines within the formation.

Chlorite also will cause productivity impairment as the result of migration. An additional problem associated with chlorite is the precipitation, over time, and drop in pH of insoluble $Fe(OH)_2$ within the formation.

Mixed layer clays will exhibit the characteristics of their component parts. They may hydrate or migrate or both.

Water filtrate will spontaneously displace oil or gas from most formation rock. Since most sedimentary hydrocarbon bearing zones are preferentially water wet and are composed of innumerable flow channels of varying diameter, the lost filtrate is held in place by capillary forces. The driving force needed to overcome the capillary adherence of lost water to the formation can be quite large. Formation pressure alone often is not sufficient to displace the filtrate and initiate flow of formation fluids into the wellbore. Marginal zones with low pressure and low permeability can be completely shut off due to this water blockage.

Oil is added to water-based mud systems as a common practice. This oil is emulsified into the continuous fluid phase by the action of surfactants. Emulsified oil serves as a lubricant and lowers the API fluid loss. If filtrate containing an excessive quantity of primary emulsifier is lost to the formation, colloidal droplets of formation fluids can be formed within the lost filtrate. The resultant emulsion acts much the same as a solids blockage, due to the physical characteristics of the colloidal droplets. In some cases, a wettability reversal may accompany emulsification. This problem is particularly evident in water wet reservoirs penetrated by oil-base filtrate.

The proper design of a workover/completion fluid is paramount to the successful initiation of production. At present, there are two distinctly different approaches to formation protection involving fluid types. One of these approaches considers the use of a totally solids-free inhibitive fluid. These fluids are commonly referred to as clear brine solutions. The inorganic salts used in the formulation of clear brines alter the ionic environment of the fluid system in a direction of ever decreasing activity levels depending upon the type and concentration of salts. The increase in salinity or, more appropriately, the increase in ionic concentration decreases the ability of hydratable clays to take on water.

Certain cations, such as potassium, can diminish swelling at relatively low concentrations due to selective bonding to the crystal lattice of the clay. Such ions, when base exchanged, more completely fill the available bond area within the interlayer region of hydratable clays. By so doing, the volume of free water storage space is diminished within the clay. Clay dehydration often results from exposure to saline solutions.

Reductions in the hydration potential of clays results in a particle that is more stable to movement caused by fluid invasion. The bonds holding the clay in place remain firm, therefore, the particle is less likely to migrate.

Clear brine fluids rely solely upon the inherent inhibiting characteristics of the soluble salts they contain. No effort is made to control the overall volume of filtrate lost to the formation. This lack of regard for filtration control can result not only in a high fluid cost, but also in formation damage caused directly by high filtration rates. Water block and emulsion formation can easily result. Also, some clays will hydrate even at relatively high salinities.

To eliminate the possibility of interaction between excessive filtrate and formation solids and liquids, the other popular approach to minimizing formation damage stresses the employment of properly sized bridging solids for filtration control. These solids-laden fluids contain soluble salts and polymers for inhibition and bridging solids for filtration control. Not only is overall filtration into the formation limited, but the hydration of formation clays is minimized by both ionic and polymeric means.

The process of controlling fluid loss by acid soluble bridging particles has been well documented. These particles are usually calcium carbonate, are readily available and come in a wide particle size range. In order for the bridge to be established, a positive differential pressure must exist to allow deposition of solids on the face of the formation.

The primary bridge is very similar to the Roman arch construction. A keystone or key particle keeps the structure from collapsing. Once the primary particles have formed the keystone, smaller particles seal the intervals between these particles. The range and distribution of these particles vary from colloidal to subcolloidal in size.

Formations are a mixture of various pore sizes. For this reason the critical size particle necessary to establish the bridge can vary. If the pore size is known, determining the critical size bridge particle is simple. Since this information is not always available, a rule of thumb may be used for the determination of proper size. The rule involves taking the square root of the permeability in millidarcys and dividing by three to determine the median pore size in microns.

The concept of using a wide range and distribution of particle sizes as the basis for designing a bridging system is widely supported. This method makes use of a median particle size. Analyses of this method shows the need for distribution of bridging particles both larger and smaller than the median particle. Another helpful guide states that the median micron particle size of the bridging agent should be equal to or slightly larger than one-third of the median micron pore size of the formation.

With the concept of bridging and polymer utilization in the workover/completion fluids industry came a host of various descriptive names. Nondamaging systems, acid soluble systems, and polymer systems were and are used to describe polymer/carbonate fluids. All these systems have several things in common. All basic fluid properties are derived from polymers and all incorporate calcium carbonate as bridging agents.

The type and diversity of polymers is great and the applications of these polymers vary from service company to service company. Polymer types can be separated into three main categories: 1) natural polymers, such as starch, guar gum, xanthan gum (XC); 2) natural polymer derivatives, such as hydroxyethyl cellulose (HEC), carboxymethyl cellulose (CMC), modified starches, lignosulfonates; and 3) synthetic polymers, such as polyacrylates, polyacylamides-vinyl polymers. All these polymers have various uses in the workover/completion fluid industry. They may be classified into two major use areas: 1) fluid loss control agents, and 2) viscosifiers. It should also be understood that all polymers are not equal when it comes to various brine water compatibility. Care must be taken when selecting a polymer that can be used with either fresh, sodium, potassium, or calcium make-up brines.

Polymer/carbonate systems have two distinct classifications: 1) nonthixotropic and 2) thixotropic. These two basic systems combine the best of all properties in a workover/completion fluid. They are inhibitive, acid soluble, form a bridge for fluid loss control, and inexpensive.

In a nonthixotropic workover system it should be remembered the density of the fluid is controlled only with solution weight and not by external weighting material. The design of this system should include control of fluid loss, viscosity, and pH. Sodium chloride, up to 10 ppg; potassium chloride, up to 9.7 ppg; calcium chloride up to 11.7 ppg; and field brine, or any combination, should be used to maximize inhibition. The nonthixotropic systems are used for 1) underreaming and gravel packing, 2) wellbore clean out, 3) sand control, 4) milling operations, and 5) and perforating.

The uses of thixotropic workover/completion fluids have changed over recent years. Calcium carbonate was used as the sole weighting material in these systems. This limited the practical working range of these systems to about 13.5 ppg. The industry then tried iron carbonate ($FeCO_3$). This increased the working density to about 16.0 ppg. Unfortunately, iron carbonate is mined along with many impurities and a standard or spec product was difficult to obtain. This led to many problems with reproducibility and reliability of the product in the field

A stable workover/completion system now can be built in the 20 ppg range using itabirite, a hematite (Fe_2O_3). This thixotropic fluid has all the applications of a nonthixotropic fluid with the exception of gravel packing. It should be remembered that all rheological properties are derived from polymers in these type systems.

Both the nonthixotropic and thixotropic systems offer advantages over heavy brines. They are available in a wide density range, low cost, nonhygroscopic, environmentally safe, available worldwide, and easy to maintain. Two limitations of these systems are 1) bacterial degradation, polymers need to be protected from bacteria even in the presence of high salinity brines, and 2) temperature, all polymers degrade at high temperatures but at different rates.

In summary, the polymer/carbonate systems offer distinct advantages over heavy brines in some areas. A properly designed bridge will be easily flushed off the formation face, or out of the perforation tunnels when the well is brought back on production. If the bridge can not be removed by back flowing the well, an acid pill spotted across perforations will dissolve any carbonate not removed. The ultimate goal of any workover/completion fluid should be maximum production and formation protection.