THE DESIGN & USE OF LABORATORY TESTS TO REDUCE FORMATION DAMAGE IN OIL & GAS RESERVOIRS

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Abstract

Formation damage causes substantial reductions in oil and gas productivity in many reservoirs. Due to the mechanics of flow into horizontal wells and the fact that most horizontal wells remain as open hole completions, damage effects can be much more severe in horizontal wells than in equivalent vertical wells. Damage can be caused by mechanical effects (fines mobilization, solids invasion, emulsion formation, water blocking), chemical effects (clay swelling, clay deflocculation, solids and wax precipitation, insoluble precipitates, acid sludges, chemical adsorption, wettability alterations), the action of bacteria or extreme temperatures associated with thermal recovery processes. Stimulation procedures required to remove formation damage in horizontal wells are costly and are often unsuccessful or marginally successful. The use of well designed laboratory programs can allow those associated with designing and conducting drilling, completion or stimulation programs to evaluate the effectiveness of specific programs, prior to their implementation in the field. This paper provides a brief discussion of the mechanisms of formation damage, and then provides details on recent advances in laboratory testing and technology which allow almost any type of drilling, completion, workover, or stimulation program to be critically evaluated. The use of these techniques can reduce completion costs and greatly increase ultimate recovery and productivity of horizontal wells in many oil or gas reservoirs.

Introduction

Formation damage is defined as any type of a process which results in a reduction of the flow capacity of an oil, water or gas bearing formation. Formation damage has long been recognized as a source of serious productivity reductions in many oil and gas reservoirs and as a cause of water injectivity problems in many waterflood projects. This paper provides a brief overview of many of the processes which can cause formation damage and discusses laboratory techniques which can be used to evaluate potential formation damage problems before they occur in the reservoir and result in substantial damage and/or costly stimulation or workover treatments.

Causes Of Formation Damage

Formation damage can potentially occur any-time non-equilibrium or solid bearing fluids enter a reservoir, or when equilibria fluids are displaced at extreme velocities. Thus, most processes used to drill, complete or stimulate reservoirs have the potential to cause formation damage. Some of these processes might include:

1. Drilling
2. Cementing
3. Completions/Stimulation
   a) Perforating
   b) Acidizing
   c) Fracturing
4. Workovers
   a) Kill fluids
   b) Hot oil treatments
5. Waterflooding or water disposal
6. Enhanced oil recovery processes
   a) Miscible flooding
   b) Chemical flooding
   c) Thermal flooding (in-situ combustion/steamflooding)
7. Excessive injection or production rates

**Why Prevent Formation Damage?**

The philosophy varies with respect to formation damage. Many are of the opinion that cheaper, easier to use drilling and completion programs should be utilized, as wells can always be fractured or stimulated after the damage has occurred to increase productivity.

1. Reducing Formation Damage generally lowers ultimate completion costs. If the extra cost of fracture, acidizing and other, often unsuccessful, stimulation programs can be avoided, substantial savings are realized. Often the cost of the design and implementation of a more effective drilling and completion program is more than offset by savings realized by the greater productivity and lack of additional stimulation work required to obtain an effective well. Also, once an effective program is designed, it can generally be applied to additional wells in the same reservoir without any extra design costs.

2. Preserve Barriers. The success of many secondary and tertiary recovery process depends upon maintaining the integrity of permeability barriers in the formation, especially when adjacent zones of widely contrasting permeability are present. Large volumes of hydrocarbons have been lost in waterfloods, miscible floods and chemical floods in reservoirs where injection or production wells have been fractured into high permeability zones.

3. Improved Sweep Efficiency. Sweep efficiency is generally much higher in wells which have not been subjected to fracture treatments due to much better conformance of the injected or produced fluids.

**Comparison Of Formation Damage In Horizontal Versus Vertical Wells**

Horizontal wells are much more susceptible to damage than their vertical counterparts due to a number of reasons, these being:

1. Substantially longer contact time with the drilling fluid. In a vertical well drilling fluid may only be in the pay zone a matter of hours while in a horizontal well the time may be measured in weeks.

2. Most horizontal wells are not cased and perforated and remain as open hole completions. Relatively shallowly invaded damage which would be easily perforated through on a standard vertical well, remains a major source of permeability reduction in many horizontal wells.

3. High drawdowns are difficult to obtain on horizontal wells due to the length of the well in the pay zone. This makes it much more difficult to clean up damage due to invaded fluid and/or solids.

4. Stimulation of horizontal wells is extremely difficult and expensive. Thus once formation damage occurs, it is usually permanent in nature and effect.

**Well Productivity**

The productivity equations which govern flow into horizontal vs vertical wells are substantially different.

If certain simplifying assumptions are made, equations for calculating the production of a horizontal well can be made. Joshi (1987), Ertekin et al (1988), Giger (1987), Joshi (1988), and Babu et al (1989) have all discussed horizontal well productivity calculations.

The discussion of well productivity in this paper is taken from Joshi (1988).

A vertical well generally drains volume in the shape of a regular cylinder while in a horizontal well of length $L$ the drainage volume is shaped like an elliptic cylinder due to the variation in vertical vs horizontal permeability. In both cases a reservoir of thickness $h$ is being drained. To solve for the pressure distribution in both horizontal and vertical wells at steady-state conditions, the equation

$$ \nabla^2 P = 0 $$

must be solved. This will give the pressure distribution which can then be used in Darcy’s law to calculate flow rates.

$$ q_w = \frac{2n k_v h A P}{(\mu_e B_e)} $$

$$ \ln \left[ \frac{a + \sqrt{a^2 - \left( \frac{L}{2} \right)^2}}{L/2} \right] = \beta h \frac{L}{L} \ln \left[ \frac{1}{(\beta + 1) r_m} \right] + s $$

(2)
Mechanisms Of Formation Damage

Formation damage falls into four broad categories based upon the mechanism of it's origin, these being:

1. Mechanically Induced Formation Damage
   i) Fines migration
   ii) Solids entrainment
   iii) Relative permeability (trapping) effects

2. Chemically Induced Formation Damage
   i) Clay swelling
   ii) Clay deflocculation
   iii) Wax deposition
   iv) Solids precipitation (asphaltenes, sulphur, diamondoids, hydrates, etc.)
   v) Incompatible precipitates and scales
   vi) Acid sludges
   vii) Stable emulsions
   viii) Chemical adsorption
   ix) Wettability alteration

3. Biologically Induced Formation Damage
   i) Bacterial growth
   ii) Bacterial slimes
   iii) Corrosion products due to H₂S from sulphate reducing bacteria (SRB's)

4. Thermally Induced Formation Damage
   i) Mineral transformations
   ii) Rock solubility and dissolution phenomena
   iii) Wettability alterations

It is not possible to discuss all these phenomena in detail, although a brief description of some of the major mechanisms follow to allow a basic understanding of the tests, which will be discussed later, which are utilized to alleviate or diagnose specific formation damage problems.

Mechanically Induced Damage

It has been long accepted that severe permeability impairment can occur when fluid velocities become large enough to physically shear interstitially bound particulates loose and move them to bridging/blocking locations at pore throats. Gray and Rex (1966), Mungan (1965), Muecke (1979), Gabriel (1983), Gruesbeck (1982), Krueger (1986), Selby (1989) and Porter (1989) all provide more detailed descriptions on the problems associated with fines mobilization.

The injection of fluids containing solids (i.e. unfiltered injection waters or corrosion products from degenerating tubing strings or surface equipment) can also cause gradual plugging and loss of permeability. Barkman (1972) and Patton (1988) discuss this phenomena in greater detail.

Deleterious relative permeability effects can also often have a severely reducing effect on effective permeability,
particular in low permeability reservoirs. An example of this is illustrated in Figure 2. The reservoir (gas in this example) is initially at saturation Sw. The near wellbore region is then invaded by an aqueous based drilling fluid, resulting in a much high irreducible water saturation Sw, (due to capillary trapping phenomena) near the wellbore. It can be seen that effective permeability to gas has been reduced substantially due to the increased trapping of the invaded aqueous phase.

**Chemically Induced Damage**

The phenomena of clay swelling, defined as the direct substitution of water into hydratable clays such as smectite is the “classic” type of formation damage which most individuals are commonly aware of. Discussion on the structure and mechanism of swelling clays is presented by Wang (1988). Expansion of swelling clays upon hydration can often cause severe reductions in formation permeability.

A much more prevalent, but less widely understood, cause of formation damage is deflocculation. Deflocculation occurs when the delicate ionic charge balance that electrostatically binds clays and particulates together and to pore walls is disrupted resulting in migration and blockage of the clays, even though they may not classically be thought of as “swelling” clays. This phenomenon commonly occurs when a system is subjected to a salinity reduction or “shock” as illustrated in Figure 3. Mungan (1965) illustrates this phenomenon in greater detail.

Solids and wax precipitation is often a problem in production wells, particularly in miscible flood projects. Thomas (1991, 1991) and Fischer (1973) discuss these phenomena in greater detail. Other solids in the form of insoluble precipitates and scales can occur due to chemical incompatibility between formation and injected fluids. These would include insoluble precipitates such as barium or calcium sulphate which can often cause severe long term permeability impairment in injection and production wells. Many acids can also chemically precipitate insoluble acid “sludges” which can cause blocking and plugging of the pore system. Acids, and other aqueous fluids, can also cause the formation of extremely high viscosity oil external emulsions which can become entrapped in the near wellbore region and form a viscous and immobile "Emulsion Block".

The injection of various types of chemical additives (surfactants, scavengers, inhibitors, polymers, stabilizers, etc.) can result in both wettability changes, which can alter permeability, and also in physical adsorption which can permanently impair permeability.

**Bacterial Growth**

Entrainment of bacteria in injected fluid streams can be a source of severe formation damage and operation problems. Bacterial formation damage can occur both with and without oxygen present (aerobic and anaerobic) and a particular type of bacterial family, sulphate reducing bacteria, have been responsible for the souring of many previously sweet gas reservoirs. Hydrogen sulphide gas can create severe problems with corrosion, as well as its extreme toxicity to living organisms (humans included). The in-situ secretion of bacterial slimes by many types of bacteria can be a cause of substantial permeability impairment, so much so that various companies have investigated the use of certain types of bacteria to plug high permeability thief zones in certain wells.

**Thermally Induced Formation Damage**

This type of damage occurs almost exclusively at temperatures exceeding 150°C in hot water, steamflood or in-situ combustion projects and has been documented by authors such as Bennion (1992), McCorriston (1981), Amaefule (1984), Waldorf (1965) and Hebner (1985). The major sources of damage can be attributed to the temperature induced transformation of inert clays such as kaolinite into swelling smectitic clay, the physical dissolution of portions of the rock matrix and release of encapsulated fines due to high temperature solubility effects and wettability changes associated with steamflooding.

**Why Laboratory Testing**

The drilling of horizontal wells in oil or gas formations is an expensive proposition for any operator. Logically, any process which will provide a reasonable chance for improving the productivity or reducing the total cost of any horizontal well is economically viable and should be considered. Recent advances in laboratory testing procedures allow for the in-depth simulation and evaluation of almost any type of drilling, completion or stimulation program considered for use in a horizontal well. This allows for considerable screening and optimization to be conducted, prior to implementing an expensive and potentially unsuccessful program in the reservoir.

**Mechanically Induced Formation Damage**

A combination of core displacement studies and particle size distribution analyses are the major types of tests beneficial in this area. Figure 4 illustrates the type of equipment used for this type of study. The core sample is encased in teflon shrink tubing and placed in a heavy lead or viton core sleeve. The shrink tubing is used to ensure that no fluid slippage occurs between the sleeve and the
core and prevents direct fluid contact with the sleeve. The ductility of the sleeve allows a confining overburden pressure to be transferred to the core to simulate reservoir pressure. The core, mounted within the sleeve is placed inside a 316 SS core holder which is capable of simulating reservoir pressures of up to 68.9 MPa (10,000 psi). This pressure is applied by filling the annular space between the lead sleeve and the core holder with light oil and then compressing the oil with a hydraulic pump to obtain the desired overburden pressure.

The core holder ends each contain two ports. One of these ports is for fluid feed or production and the second is for pressure measurement. The portions of the core holder directly adjacent to the injection and production ends of the core are equipped with radial distribution plates to ensure evenly distributed fluid flow into and out of the core specimen and eliminate areas of localized high velocity.

Pressure differential is monitored using a pressure transducer. The transducer is mounted directly across the core and measures the pressure differential between the injection and production ends. The pressure transducer range depends on the permeability of the sample being evaluated. The signal from the pressure transducer is directly connected to a strip chart recorder which provides a continuous pressure profile of the test. A digital readout also appears on a multi-channel terminal from which the test operator takes readings as a backup.

A positive displacement pump is used to inject fluids into the core. The pump is capable of injecting at rates from 1 cm³/hr to 8,240 cm³/hr at pressures up to 68.9 MPa with an accuracy of ± 0.01 cm³. The pump is filled with distilled water which displaces varsol. This varsol then displaces the brine to be used in the test into the core. This arrangement is used to avoid placing corrosive brine solutions directly into the pump. Positive displacement pumps such as this provide a very smooth displacing action which eliminates pressure shocks to the core material.

The entire system is contained in a temperature controlled oven which duplicates precise reservoir conditions of temperature and eliminates complication of data analysis due to fluctuations in the external ambient temperature. The use of the correct reservoir temperature also ensures that the correct fluid viscosities, which will occur in the reservoir, are properly simulated.

i) Fines Migration Tests

The purpose of a fines mobilization test is to determine the critical interstitial velocity at which fines migration begins to occur. This is expedited by displacing a non-damaging equilibrium brine through the core sample at geometrically increasing flow rates. Injection rate is reduced to the baseline level after each elevated rate level to eliminate effects of non-Darcy flow due to turbulence at elevated flow rates. Figure 5 provides a plot of this type of a flow phase. Figure 6 provides an illustration of a plot of interstitial velocity vs percent reduction in permeability. Most reservoirs will demonstrate a critical velocity at which fines migration occurs. Permeability may either increase or be reduced by fines mobilization, depending on the size and quantity of the migrated fines and the pore throat size distribution existing in the reservoir.

Since fines migrate only in the phase which wets them, the use of representative native-state or restored-state core samples is essential in these types of tests. Scaling of the linear velocity data in the cylindrical coreplugs back to the more complex velocity pattern around a perforated completion a typical vertical well can be facilitated by the use of a near perforation numerical simulation model as described by Eng (1991). The simulation in a typical horizontal well open hole completion can be accomplished using a less complex radial flow model.

ii) Solids Entrainment

Equipment to evaluate solids entrainment is identical to that described for fines mobilization tests, with the exception that the in-line filtration system is removed to allow the direct injection of the proposed injection fluid, complete with its load of suspended solids, directly into the core sample.

Several hundred pore volumes of proposed injection fluid can be dynamically injected into the core material and permeability continuously monitored to note the gradual effect of solids entrainment on the system. Various sizes of in-line filtration can also be tested (i.e. 10 micron vs 5 micron vs 1 micron, etc.) to determine the critical filtration level required for long term sustained injectivity. Figure 7 provides a plot of the permeability profile from a critical filtration level study illustrating, for this test, a critical filtration limit of 2 microns.

The coupling of laser refraction determined suspended particle size analysis with pore size distribution data can also be an informative screening method for critical filtration limits. In general particulates must be less in size than ½ to ¼ the diameter of the average pore throat not to cause long term bridging effects.

iii) Relative Permeability Effects

Figure 8 provides a schematic of a typical reservoir condition relative permeability apparatus. The equipment is very similar to the fines migration apparatus detailed previously (Figure 4) with the exception of the use of a backpressure regulator to allow reservoir pore pressure to be maintained to facilitate the use of live gas charged reservoir fluids. Bennion (1991) discusses recent advances in techniques used for the determination of relative permeability data. Information on phase blocking effects
can be obtained by analysis of the relative permeability curves on a combined drainage-imbibition test. This would include:

a) Water trapping in a gas reservoir (waterflood sequence from $S_w$, followed by a gasflood to $S_w$)

b) Water trapping in an oil wet reservoir (waterflood sequence from $S_w$, followed by an oilflood to $S_w$)

Chemically Induced Formation Damage

& ii) Clay Swelling and Clay Deflocculation

The coreflow equipment used for these types of tests is illustrated in Figure 9. The equipment is very similar to that described for the fines migration test with the exception that the inlet fluid manifold consists of multiple storage cylinders containing the different test brines to be evaluated. These fluids are in pressure equilibrium allowing for fluid changes to be conducted while under dynamic flow without disturbing the system pressure equilibria.

Both clay swelling and clay deflocculation tests are conducted by initially establishing a baseline permeability to a non-damaging reference fluid, generally clean formation brine, followed by displacement of the test fluid(s) and a dynamic measurement of the resulting change in permeability. Figures 10 and 11 illustrate typical results for tests for clay swelling and clay deflocculation respectively. Clay swelling is a mass transfer limited process and hence is more gradual than clay deflocculation which represents an abrupt rupture of electrostatic bonds. Thus tests which exhibit clay swelling problems are generally characterized by gradual reductions in permeability with time (Figure 10) in comparison to the case of clay deflocculation which is usually very abrupt and almost instantaneous (Figure 11).

iii) Wax Deposition.

Problems with wax deposition are commonly diagnosed on a preliminary basis by conducting a pour point determination on the system. This provides a measurement of the temperature at which solid wax deposition begins to occur. Operational strategies to keep the producing temperature elevated or the use of chemical suppression methods to lower the pour point temperature can then be considered.

iv) Solids Precipitation

Depending on the type of system under consideration, tests to quantify and reduce solids precipitation vary widely. High pressure titrative and PVT techniques are useful for determining critical solvent concentration limits and compositional limits for incipient asphaltene precipitation due to contact by miscible flood solvents or from naturally asphaltic oils (Thomas, 1991). Detailed PVT experiments can also be undertaken to determine critical concentration, pressure and temperature levels to obviate elemental sulphur, diamondoid or hydrate formation. Detailed studies are specific to the type of system being studied, but often operating conditions of temperature and pressure in production or injection systems can be optimized to reduce or in some cases eliminate phenomena associated with these types of solids deposition.

Many problems with solids precipitation occur in the production systems and surface facilities, rather than actually in the formation, due primarily to the sensitivity of solids precipitation phenomena to lower temperatures and pressures. If in-situ problems in the reservoir are anticipated, detailed coreflow experiments which will duplicate the dynamic mixing of the fluids within the reservoir porous medium at full reservoir operating conditions should be undertaken to quantify if permeability reductions will occur.

v) Incompatible Precipitates and Scales

Incompatible solid precipitates and scales generally occur when foreign fluids (generally brines) are contacted with one another. Basic turbidity (bottle tests) are a good preliminary indicator of fluid incompatibility. Detailed compatibility studies, complete with the calculation of scaling coefficients, should be undertaken for any large scale water injection scheme. Fluids rich in divalent ions such as calcium, magnesium, barium and strontium often tend to be the worst offenders in this area, even though their high divalent ion concentration may make them desirable for inhibiting formation damage from a clay swelling or deflocculation viewpoint.

Long term coreflow tests conducted using a co-injection apparatus, such as illustrated in Figure 12, can quantify the effects of long term exposure of the formation to precipitates. In this apparatus equal volumes of both the equilibrium formation brine and the injection water are simultaneously displaced through the core sample. The two brines mingle directly at the sample face, allowing in-situ precipitate formation. Co-injection can continue for an extended period of time (generally several hundred pore volumes) to note the long term effect of the precipitate deposition on permeability.

vi) Acid Sludges

Many acid blends can cause the formation of insoluble sludges. The formation of the sludge is dependant on the type of oil, acid, acid concentration, iron content and other factors. Initial screening tests are generally conducted at bench conditions to note the effect of such phenomena on the formation of sludges and/or emulsions. Tests for total rock solubility in the acid are also vital as partial solubility may cause the large scale release of acid insoluble fines.
which can migrate, plug and cause permeability impairment.

Once a suitable acid blend has been formulated based upon the results of the initial screening test it blend should be evaluated on a core sample using a flow test. Simple tests would follow the pattern of the basic fluid sensitivity test, with the acid substituted in place of the test brine. More complex tests to evaluate the actual effectiveness of acid in the removal of formation damage are discussed later in the paper in the "Fluid Leakoff" section.

Since CO₂ gas is generally liberated during an acid reaction test with a core sample, it is recommended that these types of tests be conducted under full reservoir backpressure. This will solubilize the produced CO₂ gas in the flowing aqueous stream and eliminate the formation of a trapped residual gas saturation in the core material which could artificially reduce the effective fluid permeability due to deleterious relative permeability effects.

vii) Stable Emulsions

The formation of stable emulsions can cause up to tenfold increases in fluid viscosity. This is a particularly prevalent problem in low gravity crude oil reservoirs (<25 °API), but also can occur in medium gravity and waxy high gravity crude oil systems. The propensity for the formation of stable emulsions at both bench and reservoir conditions can be determined by dynamic mixing studies in the laboratory. The use of various surfactants to break stable emulsions can also be investigated easily and inexpensively in a similar fashion. Dynamic coreflow tests, coupled with Scanning Electron Microscope (SEM) work and precise permeability measurements can ascertain whether the in-situ formation of emulsions within a given porous medium will have a reducing effect on permeability.

viii) Chemical Adsorption

Many compounds, particularly polymers and polar additives, can be physically adsorbed or the rock surface. Additive retention generally has a reducing effect on permeability, particularly if the adsorbed compounds consist of large molecules such as long chain polymers.

Simple coreflow tests consisting of baseline brine or oil permeabilities, followed by exposure to a specified number of pore volumes of test fluid (in the reverse direction), followed by a regain permeability to the initial oil or brine can quantify the degree of damage associated with the use of a certain additive. Once damage has occurred the effect of various stimulation treatments (such as additives, oxidizing agents, enzymes, etc.) can be evaluated.

ix) Wettability Alteration

Wettability alterations (from a water to oil wet state) can substantially reduce the permeability to oil, and substantially increase the permeability to water, effectively lowering oil productivity. Since a large majority of chemical additives, particularly many surfactants and corrosion inhibitors, tend to cause shifts towards oil wetness, a good understanding of how these chemicals may alter productivity is essential.

Wettability can initially be screened on restored-state or native-state core using simple methods such as contact angle determinations, or more sophisticated methods such as an imbibition or combined Amott/USBM wettability study. Oil-water relative permeability measurements can also often provide a good estimate of initial wettability (Craig, 1971). The test samples can then be exposed to the test additives and wettability re-evaluated to determine the effect of the proposed chemical additives. Figure 13 provides an illustration of this type of phenomena for a transition from a water wet to an oil wet system using the contact angle method. Figure 14 illustrates a similar phenomena for a test using comparative relative permeability curves. The relative permeability evaluation also provides an indication of how radically the flow characteristics of the system can be altered by a shift in wettability.

Leakoff Tests

Normal drilling, completion or stimulation practices generally will involve a combination of damage mechanisms. For example, during drilling damage could occur due to a combination of solids entrainment, chemical adsorption, relative permeability and clay swelling or deflocculation effects induced by filtrate invasion. Figure 15 provides an illustration of the fluid leakoff apparatus which can be utilized to simulate virtually any type of drilling, completion or stimulation operation at any overbalanced (or underbalanced) pressure condition at full reservoir operating conditions for a horizontal well.

Depending on reservoir heterogeneity either plug (3.81 cm OD) or full diameter (up to 10.16 cm OD) core samples can be utilized. Restored-state or native-state core is desirable to preserve wettability as fluid leakoff rates can be significantly influenced by formation wettability. The system is applicable to oil or gas reservoirs and is designed with a twin backpressure regulation system which allows any type of overbalanced or underbalanced operating condition.

A normal test is conducted by determining an initial baseline reference permeability to oil or gas at the initial water saturation in the reverse flow direction at full reservoir conditions of temperature and pressure. This provides the initial "undamaged" reference permeability. The leakoff test is conducted by circulating whole drilling mud (or frac fluid, acid, etc.) across the injection face of the core through a
specially designed core head. The injection fluid is contained in a temperature controlled piston which is under continuous agitation which facilitates the circulation of a homogeneous fluid system, even when the test fluid may contain suspended particulate bridging or fluid loss agents. Overbalance pressure can be precisely regulated by setting the backpressure regulation system at the injection face of the core (which is being subjected to the circulating fluid flow) at the desired bottomhole pressure. Backpressure at the production side of the core is set at the reservoir pressure value, thus duplicating the net overbalance pressure forcing fluid to leak off into the reservoir.

During the leakoff phase the dynamic leakoff rate as a function of time can be determined, as well as the total depth of filtrate invasion and time to fluid seal off (if a fluid sealoff does in fact occur). Figure 16 provides examples if some typical profiles from a mud leakoff experiment on a given rock type.

Once the leakoff has been completed, the permeability to oil or gas is redetermined in the reverse flow direction to simulate production back out of the reservoir after the treatment. Figure 17 provides some sample plots of typical regain permeability profiles. In this manner the amount of total formation damage associated with the use of a specific mud system can be determined.

This type of test is extremely useful for comparative evaluation of different drilling mud systems in that it allows:

a) Direct evaluation in field units of expected fluid loss
b) Evaluation of effectiveness of fluid loss agents
c) Determination of depth of filtrate invasion
d) Degree of permanent permeability impairment caused by mud invasion

Although specifically well suited to drilling fluids, the leakoff apparatus and test as described is applicable to any type of invasive whole fluid system. This would include gelled fluids, CO2 charged fluids, etc. Also once formation damage has occurred due to mud or another fluid invasion, acid leakoff or squeeze tests or other stimulation treatments can also be duplicated using this same type of apparatus to evaluate the effectiveness of specific stimulation programs in damage removal.

**Biologically Induced Formation Damage**

Figure 18 provides a schematic of the apparatus which can be used to evaluate formation damage due to bacterial action. This apparatus operates at reservoir conditions and uses rigorous sterilized lines and equipment to generate representative growth profiles. The test core sample is generally pressure tapped in one or more locations to determine the specific location in the sample where the formation damage is occurring and also to facilitate testing samples for compositional and bacterial analysis at different locations down the length of the sample. These tests are generally long term, low rate exposure runs (30 - 90 days in length) with continual analysis of the sectional permeability as well as regular detailed analysis of the influent and effluent liquid streams for the presence of bacterial agent products (pH changes, sulphide content, H2S content, etc.). Post test sectioning of these samples in a microbiological lab indicates how the bacteria propagates (i.e. whether it remains at the injection face or invades into the formation) and how the bacterial colonies grow and block the formation.

**Thermally Induced Formation Damage**

Figure 19 provides a schematic of the apparatus used to conduct high temperature sensitivity studies. Special coreholders and alloy sleeves are utilized in these tests which can facilitate running experiments at temperatures up to 340°C for hot water/steamflood tests and up to 1,200°C for in-situ combustion runs.

Permeability reductions at elevated temperatures can occur due to a combination of mineral transformation, dissolution and wettability effects as discussed previously. Coreflood experiments at high temperatures at reservoir conditions using preserved or restored core, reservoir fluids, reservoir injection rates and steam are the only accurate methods of predicting a reservoir's potential for thermally induced damage. Many high permeability reservoirs may produce reasonably well on primary production, but perform poorly under thermal stimulation due to a combination of the above phenomena. Prior to the extensive capital investment for a thermal recovery project it is therefore essential that sensitivity testing in this area be conducted. Well designed tests of this type can also yield valuable additional information with respect to residual oil saturations and oil and water relative permeabilities as a function of temperature. Figure 20 illustrates the effect of temperature on water permeability for a high permeability consolidated sandstone formation.

**Conclusions**

Formation damage is a significant problem that has the potential for reducing productivity in horizontal wells in oil and gas reservoirs during almost any type of drilling, completion or stimulation operation. Through the use of high technology laboratory studies, the effects and benefits or disadvantages of various proposed drilling, completion or stimulation programs can be examined and weighed in the laboratory, prior to the expense and risk of implementing them in the reservoir. The careful use of well designed laboratory programs can thus reduce costs and increase productivity in many oil and gas reservoirs.
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References


