Mechanisms of Formation Damage and Permeability Impairment Associated With the Drilling, Completion and Production of Low API Gravity Oil Reservoirs
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ABSTRACT
The economic production of heavy oil reservoirs requires an in-depth understanding of the specific mechanisms of formation damage which are unique to these types of formations. This paper will provide a brief description of some of the dominant mechanisms of permeability impairment which can occur in low API gravity oil-producing zones. These include:

1. Drilling induced damage
   - solids entrainment
   - fines migration
   - rock/fluid incompatibilities
   - fluid/fluid incompatibilities
2. Reactive clay induced damage
3. Formation of emulsions (water-oil, oil-water)
4. Foamy oil phenomena
   - Sand control and consolidation issues
5. Completion induced damage, acidizing, solvent injection, etc.
   - Thermally induced formation damage
   - mineral transformations
   - mineral and formation dissolution
   - wettability alterations
6. Biologically induced formation damage issues

This paper provides a general overview of many of the potential types of formation damage which drilling, production and reservoir engineers as well as geologists and geophysicists should be aware of when planning exploitation programs for heavy oil plays.

INTRODUCTION
Heavy oil reservoirs present a unique challenge to reservoir and exploitation engineers as they exhibit properties not commonly found in normal more conventional API gravity oil reservoirs. These include:

1. Properties associated directly with the heavy oil such as high asphaltene (and possibly paraffin) content, extreme viscosity, solids content and a propensity to form stable water in oil or gas in oil emulsions.
2. Many heavy oil producing formations are contained in poorly consolidated or unconsolidated sandstone formations in many locations in the world. These particular types of formations pose their own particular challenge with respect to content of reactive clays, potentially mobile fines, mineral transformations and the physical problems associated with sand retention and control during normal production operations.

References and illustrations at end of paper
This paper will attempt to quantify in a brief descriptive manner many of the common mechanisms of formation damage which should be considered when drilling and completing heavy oil reservoirs, and provide indications of potential techniques which may be considered to attempt to reduce or eliminate some of the concerns associated with these particular formation damage mechanisms.

MAJOR FORMATION DAMAGE MECHANISMS IN HEAVY OIL RESERVOIRS

Major formation damage mechanisms in heavy oil reservoirs can be subdivided into four major classifications, these being:

1. Mechanically induced formation damage
2. Chemically induced formation damage
3. Biologically induced formation damage
4. Thermally induced formation damage

Each of these will now be discussed in greater detail

Mechanically Induced Formation Damage Mechanisms

Physical Migration of In-Situ Fines

Many heavy oil reservoirs are clastic formations which contain a high concentration of potentially mobile, in-situ fines and particulates. These could include clays such as kaolinite, detrital rock fragments, pyrobitumen or other potentially mobile materials. Heavy oils occurring in carbonate reservoirs are also not immune to fines migration phenomena as documented instances of the migration of dolomite or carbonate fines, pyrobitumen, etc. have also been observed in this type of reservoir application.

Fines migration is controlled by a number of factors including wettability of the porous media (fines generally tend to migrate fairly exclusively in the phase that wets the rock). This phenomena is illustrated in Figure 1. Pore size distribution and size of fines, as well as velocity of the fluids flowing in the interstitial space, also strongly control the severity of problems associated with fines mobilization. Fines migration can be controlled in a number of fashions in heavy oil reservoirs, ranging from reducing apparent velocity by utilization of openhole completions, selective fracturing jobs or, in some situations, potentially mobile clays can be stabilized through the use of chemical clay stabilization treatments which have been described by a number of authors[1,2].

Sand Control and Production Issues

A major problem associated with the production of heavy oils and bitumens from many low API gravity crude oil reservoirs is the fact that it is very difficult to produce the bitumen without producing large quantities of entrained formation fines and sand. A variety of techniques to retain sand such as pre-packed screens, openhole gravel packs, formation consolidation treatments, frac and pack treatments, etc. have been attempted, in many situations over the years, with varying degrees of success. General consensus among operators often is that, when sand production is significantly reduced, oil productivity also tends to be significantly reduced. A number of different authors have investigated gravel packing as a technique for sand retention[3,4]. Bennion et al[5] provides a detailed discussion of gravel pack sizing criteria for the Rosary sands in the Ballarat reservoir. This study illustrates significant reduction in gravel pack permeability and ultimate well productivity is achieved if poor gravel pack sizing is selected which allows the physical invasion of produced particulates and fines from the formation into the gravel pack. The authors also postulated, based on results in both Canadian and Bakersfield heavy oil producing operations, that many of the problems associated with restricted gravel pack production may be related to near wellbore disturbance and damage phenomena associated with problems in the original drilling and completion operations. It was discovered that, if invasive formation damage and near wellbore disturbance could be minimized during the original drilling and completion operations, near wellbore consolidation and sand control problems were much less problematic resulting in significantly (500%) greater productivity on the post-gravel packed wells.

Solids Entrainment Phenomena

Figure 2 provides a schematic illustration of the mechanism of solids entrainment into homogeneous matrix type systems which are commonly encountered in most heavy oil applications.

Solids invasion is a common occurrence which happens during overbalanced drilling and completion operations due to the fact that the hydrostatic pressure in the circulating fluid system is usually greater than the formation pressure. Due to the relatively high permeability of most low API producing gravity oil horizons, this results in relatively large pore throats and a significant propensity for the physical invasion of both artificial solids (ie. weighting agents, fluid loss control agents or artificial bridging agents) or naturally occurring drill solids (silicate, carbonate, dolomite or other formation fines) into the formation.
In general, many studies conducted indicate that the formation acts very much like a large filter element, filtering out the majority of the entrained solids in an area relatively close to the wellbore. In many situations, if a cased and perforated completion is being contemplated, a relatively shallow amount of invasive formation damage (less than 2 cm in depth) is usually not significant, as perforation charges will usually penetrate well beyond this radius. However, if extremely high permeability formations are encountered, or if drilling and completion in highly overbalanced conditions in a pressure depleted formation occurs, it is documented that invasive solids damage can extend a significantly greater distance into the formation. Also, a large number of completions in heavy oil reservoirs, particularly with respect to horizontal wells, tend to be either openhole, slotted liner or gravel pack type completions. In this type of situation, the remaining zone of high skin induced by the invasion of artificially or naturally occurring drill solids remains a problematic barrier to production and must be physically produced through, and therefore becomes of much greater significance with respect to impaired productivity. Past experience with laboratory studies and field studies indicates that this particular mechanism of formation damage in many openhole horizontal wells which have been completed in low API producing reservoirs plays a significant role in reducing productivity.

This problem can be obviated in many situations by appropriate design of a fluid system with the appropriate size distribution of granular bridging agents to create an effective, sealing, impermeable filter cake very rapidly upon the face of the formation, thereby inhibiting continual losses of small solids and potentially damaging mud filtrate into the formation. This phenomena is further illustrated in Figure 2.

A variety of bridging agents are available for this purpose, including calcium carbonate, oil soluble resins, cellulosic materials, sized salt, etc. Care should be taken in the selection of a bridging agent with respect to the completion practices proposed for the well to ensure that, if permanent entrainment of the bridging agent does occur, an acceptable stimulation technique is available to remove the bridging agent without damaging the formation.

Another potential mechanism of permeability impairment associated with solids entrainment can occur during water injection or water disposal operations in heavy oil applications. Strict filtration criteria must be maintained in order to avoid long-term plugging of the sand face by suspended solids. This phenomena is illustrated in Figure 3. Bennion provides additional criteria with respect to water filtration and water quality concerns associated with water injection and disposal operations.

General screening criteria suggests that the long-term buildup of an external stable filter cake causing significant reductions in permeability during water injection, can be avoided by ensuring that filtered injection water is filtered to a size distribution of particulates of less than approximately 20% of the median pore throat size diameter of the target formation.

Relative Permeability Effects

Water trapping and retention or aqueous phase trapping (APT) is not usually considered to be a significant permanent problem in many heavy oil reservoirs due to the fact that:

The majority of heavy oil reservoirs exist at some initial water saturation comparable to what would be considered the ultimate irreducible water saturation.

2 The majority of heavy oil reservoirs exhibit high permeability and porosity characteristics and correspondingly low apparent capillary pressures which also tend to reduce the propensity of damage associated with permanent aqueous phase trapping.

Bennion further discuss this phenomena. Figure 4 provides a schematic illustration of relative permeability curves showing the mechanism of an aqueous phase trap in an oil or gas situation. In general, due to the high permeability pre-existing in heavy oil reservoirs, they may susceptible to a non-permanent phenomena which is called an aqueous phase load. In this situation, a substantial amount of water-based fluid is lost to the formation directly adjacent to the wellbore. This creates an adverse relative permeability effect in the highly water saturated zone which results in a significant reduction in the apparent relative permeability to oil. This phenomena generally (if it is not accompanied with other damage mechanisms such as the formation of emulsions, fines migration or clay reactions) can be gradually cleaned up over a period of time if a sufficient pressure gradient can be mobilized within the formation over the invaded zone to produce the fluid back to the wellbore. This may result in impaired productivity for a period of time and hence, although permanent reductions in permeability in heavy oil reservoirs due to the establishment of aqueous phase traps, may occur, short or medium term reductions in production rates can be readily apparent when wells are unnecessarily killed or subjected to high amounts of invasion with water-based fluids. The lower the permeability of the formation, the more significant the propensity of aqueous phase trapping and permanent retention of water problems becomes. Figure 5 provides a schematic example showing the relative severity of potential aqueous phase traps as a function of initial water saturation and permeability in porous media. If a low permeability heavy oil play at a low water saturation is under consideration, care should be taken to avoid
the introduction of potentially damaging aqueous phase fluids into the formation.

Slugs of skim oil or entrained oil during water injection and water disposal can also have adverse relative permeability effects, particularly if the targeted injection zone is an aquifer or entirely water saturated disposal zone. Further information on this phenomena is contained in Bennion[19]. This phenomena is schematically illustrated as Figure 6 and is especially problematic with heavy oils, due to both the difficulty in separating produced water and heavy oil emulsions prior to re-injection and the tarry nature of heavy crude oils and their ability to rapidly wet and form high residual oil saturations in porous media.

In order to eliminate concerns with skim oil injection, suspended oil in water content should be kept less than 100 ppm with the suspended oil being injected as a finely divided oil in water emulsion, rather than a nucleated solution where free oil droplets can coalesce and, instead of moving with the bulk injected fluid stream, can be entrapped in the porous media as a residual oil saturation.

Foamy Oil Phenomena

Considerable interest has been expressed in recent years in the generation of stable foamy oil emulsions, both at downhole and surface conditions, as both a mechanism for the increased and, in some cases, reduced production of oil from heavy oil reservoirs. A number of authors have discussed foamy oil behavior[11-14].

Foamy oil emulsions are created due to the high inherent viscosity and interfacial tension characteristics exhibited between gas and crude oil, as pressures are reduced below the bubblepoint pressure. General research at Hycal indicates that a certain critical threshold pressure must be exceeded to generate the formation of a true foamy oil emulsion. This pressure, in past experience, has been a function of the oil gravity, temperature conditions and oil composition which exists in the reservoir, but generally falls in the pressure range of approximately 700 - 1400 kPa. Upon the formation of a stable gas in oil emulsion, a large portion of gas which would otherwise be liberated as free gas remains entrapped in the oil in an emulsion form. This causes a reverse formation volume factor phenomena and a rapid expansion in swelling of the crude oil which is postulated to be the primary mechanism associated with the high production rates which are often associated with foamy oil reservoirs. In-situ viscosity measurements indicate that foamed oil emulsions can exhibit significant increases in apparent viscosity due to the entrainment of the gas in solution. This increase in viscosity, coupled with the presence of the gas saturation both entrapped within the porous media, has been documented to cause significant reductions in the apparent productivity and overall permeability to oil. Therefore, the radical expansion effect caused by the entrainment of the residual gas saturation is partially counteracted by reduced productivity and permeability impairment associated with the entrainment of the foamy oil. This also results in increased pressure drawdowns and gradients near the wellbore, and may aggravate problems associated with sand control. There has also been some evidence that the stable interfaces between the gas and oil phases in the foamy oil emulsions can act as transportation sites for small fines which may exacerbate problems with fines migration, sand transport and formation consolidation.

Emulsions

Emulsions are a problem associated with many heavy oil operations where both oil and water are simultaneously being produced. Bennion[19] discusses the formation of emulsions in situ at elevated temperatures in porous media. With respect to water in oil emulsions, two different types of emulsions are possible - the water-in-oil emulsion, which tends to be the most problematic as it exhibits very high apparent viscosity in comparison to clean oil, and the less problematic oil-in-water emulsion.

Water in oil emulsions are generated by a number of documented phenomena including turbulence, the presence of sand, silt or dispersed fines, paraffins, iron sulphide, asphaltenes and resins, and a variety of organic acids and cyclic and aromatic hydrocarbon compounds.

The major problem associated with the formation of water in oil emulsions is the extremely high viscosity exhibited by these fluids. Over four orders of magnitude increases in viscosity caused by the generation of stable water and oil emulsions has been documented in the literature. Some examples in recent laboratory evaluations illustrated produced emulsion from Batkum area firefloods with reservoir temperature viscosities in the range of approximately 35 000 mPas in comparison to clean oil viscosities from the same field of 190 mPas.

The formation of emulsions downhole results in the generation of a high viscosity oil which can impair fluid flow towards the wellbore. Research generally indicates that, although emulsions do tend to form in-situ in porous media, the majority of the extremely tight and highly viscous emulsions that are often encountered on surface appear to be generated in downhole pumping and surface transfer equipment.
A variety of other potential agents may result in the formation of stable in-situ emulsions. One of these agents which will be discussed in greater detail later is hydrochloric acid which, in a spent form, particularly in the presence of high concentrations of acid, can spontaneously emulsify with many heavy oils to generate extremely viscous emulsions which may result in a temporary or permanent blocking effect in the near wellbore region.

Clay Reaction

Since the majority of heavy oil producing formations are often contained in elastic formations, a variety of different types of authigenic and detrital clays may be present such as kaolinite, smectite, mixed layer clays, chlorite and illite. Each of these particular clays has their own potential sensitivity with respect to different types of formation damage mechanisms. Kaolinite clay, as already mentioned, has a propensity to be susceptible to velocity induced migration associated with high flow rates and pressure shocks. Mixed layer or smectitic clays (Figure 7) are susceptible to swelling caused by contact with either low salinity or fresh water. The expansion of the smectitic or mixed layer lattice can cause a constriction in the pore system and result in substantial reductions in permeability. This phenomena has been well documented by a number of authors.(16)

Another potentially significantly damaging mechanism of permeability impairment in unconsolidated sandstone reservoirs containing heavy oils is that of clay deflocculation. Clay deflocculation is less well understood than clay swelling and represents a disruption of electrostatic bonds which are holding the clays together in a bound or flocculated state. Abrupt contact with a pH shock or significant alteration in brine chemistry (such as the introduction of fresh or low salinity water) can cause a disruption of these electrostatic forces and result in dispersion of the clays and subsequent migration and significant reductions in permeability due to blocking and bridging. This phenomena is discussed in detail in the literature(17) and is schematically illustrated in Figure 8.

In many cases, producing heavy oil formations are inadvertently damaged by the use of low salinity or fresh water simply because preliminary petrographic analysis indicates an absence of classical fresh water swelling clays such as smectite. A variety of other particulates, including kaolinite clay, can be susceptible to deflocculation induced damage and this can have significant results with respect to impaired productivity.

Wax and Asphaltene Problems

Many heavy crude oils contain a high concentration of asphaltene. This may not necessarily be a significant problem if the asphaltenes are peptized (suspended or solubilized in the crude oils). It is only when the asphaltenes are destabilized and flocculate from solution as solid bodies that significant reductions in both in-situ permeability and plugging in surface production and treating equipment may become problematic. Asphaltenes are typically destabilized by reductions in temperature and pressure or by contact with precipitative agents such as unsequestered hydrochloric acid or a variety of organic materials such as non-compatible oils or diesel or gaseous treating agents such as LPG or carbon dioxide gas.

Most heavy crude oils do not naturally destabilize asphaltenes with normal reductions in temperature or pressure, but may be fairly susceptible to the formation of asphaltic sludges when contacted with some of the aforementioned precipitative agents. Therefore, before any type of acidization or chemical stimulation treatment is attempted, it is usually advisable to conduct extensive compatibility tests to ensure that the formation of either asphaltic based sludges or emulsions does not occur in-situ upon contact with the potential stimulation or treating fluid.

Paraffins are more problematic in some situations with heavy oils and are generally controlled by reductions in temperature. In many situations, paraffin problems tend to be more of a production issue rather than a downhole issue as generally, at reservoir temperature conditions, temperature remains sufficiently high enough to inhibit the formation of crystalline waxes. Detailed cloud and pour point measurements can be undertaken on produced heavy crudes to ascertain the precipitation characteristics of the crudes as well as solid hydrocarbon analysis to quantify the fraction of white vs black wax can be undertaken to ascertain whether wax treatments are better accomplished using thermal or chemical suppression treatment methods. Thomas(17,18) provides additional insight into the methods of the prediction and mitigation of problems associated with solids precipitation in porous media.

Biologically Induced Formation Damage Mechanisms

Bacteria can be introduced into the formation at any time during drilling, completion, stimulation or workover operations when aqueous phase fluids are utilized and improper bacteriological control is maintained. Bacterially induced formation damage is a particularly insidious type of formation damage in that the apparent deliterious effects of the introduction of the bacterial agents are usually not readily apparent, but are of a delayed and usually significant onset. Bacteria which can be problematic in heavy oil reservoirs fall into two types, classified as aerobic and anaerobic. Aerobic bacteria require a constant source of dissolved oxygen to survive and are usually only problematic in long-term water injection operations. Anaerobic bacteria require no dissolved oxygen and tend to be more widespread and problematic in a number of different scenarios.
Bacteria thrive best at a temperature range between approximately 40°C to approximately 70-80°C but can actively propagate at temperatures as low as 20°C and at temperatures of up to 135°C for very hardy strains. There are three major problems associated with the introduction and propagation of bacteria in porous media. These being:

**Plugging** - bacteria produce extremely high molecular weight polyacharride polymer and form a biofilm upon the surface of the formation to protect themselves from fluid shear. The physical adsorption of this biofilm can cause a significant reduction in injectivity or productivity of a given well over an extended period of time. Oxidants such as bleach or peroxyde are commonly used to both reduce and desorb the polymer and kill colonies of growing bacteria.

**Corrosion problems** - bacteria, when colonized on metal surfaces, form small electrochemical cells which result in a hydrogen reduction reaction which causes the corrosion and pitting problems on surfaces such as downhole tubing, pumps and in surface facilities.

**Toxicity concerns** - sulphate reducing bacteria, a particularly troublesome family of anaerobic bacteria, metabolize elemental sulphate which may be present in naturally occurring formation water or injection waters and create toxic hydrogen sulphide gas as a by-product. This H₂S gas is highly soluble in oil or water and can be potentially toxic or lethal to human beings in concentrations of greater than approximately 1000 ppm. Documented cases of sulphate reducing bacteria producing in-situ H₂S concentrations in excess of 20,000 ppm have been illustrated in areas such as the East Wilmington field in California and the Kuparik field in the North Slope in Alaska.

Biological damage problems are extremely difficult to remediate, particularly with sour gas once the gas has propagated a considerable distance into the reservoir. Therefore, the best technique associated with biologically induced damage is to ensure continuous and diligent monitoring of surface and downhole bacterial levels using rapid detection field kits and an aggressive biocide and treating program for not only continuously injected fluids such as injection water, but also any fluids used for drilling, completion, workover or stimulation operations is rigorously implemented.

**Thermally Induced Formation Damage**

Thermally induced formation damage is a family of potential damage mechanisms which are unique to the production of heavy oil reservoirs by hot water, steam or in-situ combustion enhanced oil recovery mechanisms. The nature of mechanisms of thermally induced formation damage would fall into the following classifications:

**Mineral Transformations**

At temperatures in excess of approximately 200°C, the potential for mineral transformations is present. This occurs when a relatively inert clay such as kaolinite is transformed into a fresh water sensitive clay such as a smectite. This reaction has been documented by various authors(19,20). Subsequent contact of fresh steam condensate with the newly transformed fresh water reactive clay can result in significant swelling and expansion and large reductions in apparent permeability of the pore system. This phenomena has been well documented in many thermal operations throughout the world.

**Solubilization and Precipitation**

Another potential mechanism of thermally induced damage is that the solubility of both carbonates and silica increases in aqueous solution as temperature is elevated. This can result in the dissolution of portions of the formation. This can have a twofold effect. Firstly, the dissolution may dissolve partially soluble clasts of carbonaceous or silicate material, thereby releasing previously immobilized fines which subsequently migrate to pore throats and cause reductions in permeability and productivity. Secondly, the mineral saturated brine, as it moves further into the formation, encounters colder formation material and subsequently cools and loses the ability to maintain the materials dissolved in solution. This results in re-precipitation of calcium, magnesium or silicate based solids and the magnitude and location of this re-precipitation can also result in potential reductions in permeability and productivity. A schematic illustration of both these phenomena appears as Figure 9.

**Wettability Alterations**

Wettability of porous media is strongly controlled by the physical adsorption of heavy polar constituents on the surface of the rock. This adsorption is governed by temperature considerations. As temperature becomes higher, the amount of physical adsorption decreases and many of the heavy polar constituents tend to be physically desorbed from the surface of the rock. This generally results as temperature increases in formations tending to become more and more water-wet. This is schematically illustrated in Figure 10. This generally has favorable connotations in that the relative permeability to oil is generally increased while the relative permeability to water is reduced. This is particularly beneficial in cyclic steamflood projects where the mobility ratio
is dramatically increased resulting in higher oil production on the production cycles. If the relative permeability to water is severely depressed by temperature induced wettability alterations, it may result in reductions or restrictions in injectivity of hot water or steam into the formation. Generally, this is not a concern as at high temperature the viscosity reduction associated with the increased temperature with the injection water or steam is sufficient to overcome the corresponding reduction usually noted in the relative permeability.

There have also been some isolated incidences of significant long-term wettability alterations caused by steamflooding operations. In this situation it is postulated that, when steam temperature is achieved and the connate water layer present in the porous media is vaporized and removed, a portion of the residual oil saturation is allowed to directly contact the rock and establishes an oil-wet film on the surface of the formation. This causes a rapid transition from a strongly water-wet to a strongly oil-wet scenario and a large increase in the water phase relative permeability and subsequently degrades the performance of any type of a cyclic steam operation resulting in high produced water cuts and poor recovery to oil. This phenomena has been documented in the laboratory on both a permanent and a transitory basis and is discussed in Bennion(19).

Absolute Permeability Changes

Conflicting evidence exists in the literature on the effect of temperature on absolute permeability. In general, increases in temperature result in an increase in compression on the grain to grain contacts caused by thermal expansion effects associated with the porous media. This generally has a moderate to slight reducing effect on the effective absolute permeability of the rock. Previously mentioned problems such as dissolution and re-precipitation can also result in motion of in-situ particulates and changes in pore geometry which may have increasing or reducing effects on the apparent absolute permeability of the porous media. For this reason, elevated temperature absolute permeability measurements are difficult to conduct in a reproducible fashion due to the fact that a considerable amount of permanent physical alteration in the rock character occurs from the start to the conclusion of the test sequence, eliminating the possibility for reproducible repeat control permeability measurements.

Acidizing in Heavy Oil Reservoirs

Well designed acid treatments can be of benefit in some situations when heavy oil reservoirs are being produced from carbonate or dolomite formations or from sandstone formations containing a high fraction of carbonaceous material. In some situations, well designed hydrofluoric acid treatments have also been effective in decomposing and removing clay and drilling induced damage in unconsolidated sandstone formations. In general, however, the use of hydrochloric acid or hydrofluoric acid in predominately quartose heavy oil bearing reservoirs is not advised as a primary completion treatment due to the potential problems which can often be associated by adverse interaction of acid both with the formation and with the in-situ crude in the porous media. These problems would tend to include:

- A propensity for most acids, particularly when spent and in the presence of high concentrations of iron, to spontaneously emulsify with many heavy crude oils creating extremely high viscosity tight emulsions and asphaltic based sludges which tend to have a plugging effect in the porous media.

- Potential precipitation problems associated with the use of hydrofluoric acid and reaction with carbonate or other potential materials which are present in the porous media. If hydrofluoric acid is to be considered, a detailed compatibility program and an extensive design program and staged acid job, complete with pre-flush treatment of carbonaceous material, should likely be conducted in order to minimize potential concerns associated with fluoride based precipitates.

Heavy Oil Production and Horizontal Wells

Heavy oil production in many areas of the world has increased substantially in recent years with the advance of horizontal drilling. Horizontal wells are particularly susceptible to a variety of formation damage induced mechanisms due to their geometry and completion characteristics. Horizontal wells are more susceptible to formation damage for the following reasons:

1. Increased propensity for invasion of both liquids and solids during overbalanced drilling operations due to extended exposure times.

2. Even shallow invasive damage can often be significant in horizontal wells due to the fact that the majority of horizontal wells, particularly in heavy oil applications, are either openhole or slotted liner type completions and production must occur through the damaged zone.

3. If damage does occur, obtaining penetrating stimulation treatments is difficult and expensive due to the size of the exposed area and the limited ability to obtain zonal isolation in many situations where slotted liners are present.

4. Formation damage effects are accentuated by permeability anisotropy effects in lower K_v to K_h permeability ratio formations. This is often the case in many heavy oil situations where, due to depositional environment, laminated vertical permeability barriers exist. Additional detailed discussion on potential severity of permeability impairment
with respect to anisotropic permeability impairment is contained in the references\textsuperscript{21-24}.

Laboratory Tests to Evaluate Formation Damage Mechanisms in Heavy Oil Reservoirs

A wide suite of available laboratory technology exists to evaluate many of the potential formation damage mechanisms which have been discussed in this paper. A proper understanding of the petrology and geology of the reservoir coupled with the flow characteristics of the rock, wettability, emulsification potential of the crude oil and specific tests with relationship to pore size distribution and solid size distribution of the fluid systems and composition of the fluid systems proposed for drilling, completion or stimulation can be evaluated in controlled laboratory situations to obtain a significant degree of confidence in the proposed viability of specific drilling, completion, production or operation scenarios. Additional information on specific laboratory procedures utilized for both conventional and heavy oil formation damage operations is contained in the literature\textsuperscript{21-24}.

CONCLUSIONS

A wide range of different potential types of formation damage mechanisms have been discussed for heavy oil reservoirs. These have been broadly classified into the subclassifications of mechanical, chemical, biological and thermally induced formation damage. In the majority of operations in heavy oil, much of the formation damage is typified to be of the mechanical nature with physical invasion of solids and the formation of emulsions being some of the more problematic offenders in many operational situations. A proper understanding of the rock character involved in a particular heavy oil reservoir coupled with a proposed fluid program and the interaction of the fluids and contained solids within the porous media is essential in understanding and minimizing potential problems associated with formation damage which will result in apparent reduction in the productivity or injectivity.

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**FIGURE 1**
ILLUSTRATION OF EFFECT OF WETTABILTY ON FINES MOBILIZATION

Case 1 - Non-wetting phase in motion - minimal fines migration

Case 2 - Wetting phase in motion - possible potential for fines migration

**FIGURE 2**
SOLIDS INVASION INTO A HOMOGENEOUS PORE SYSTEM

Effective External Filter Seal

Internal Filter Seal

For Small Plates & Fibers

10 micron pore throat
1 micron solids

10 micron pore throat
1 micron solids & some smaller solids

**FIGURE 3**
MECHANISM OF SUSPENDED SOLIDS ENTRAINMENT

High Velocity (>10 cm/minute interstitial)

Injection Water

External Filter Cake

k > 33% dpore

Internal Filter Cake

33% < d < 14% dpore

Non-Bridging Solids

k < 14% dpore
FIGURE 4
MECHANISM OF AQUEOUS PHASE TRAPPING

FIGURE 5
SEVERITY OF AQUEOUS PHASE TRAPPING
FIGURE 6
EFFECT OF SKIM OIL CONTENT ON NEAR WELLBORE INJECTIVITY

No Pre-Existing So, - Severe Damage
Initial k_w = k_w = 100 mD
Final k_w = k_w = 10 mD (example)

Small Pre-Existing Immobile So, - Potential Damage
Initial k_w = k_w = 50 mD
Final k_w = k_w = 10 mD (example)

Pre-Existing Mobile So, - Minimal Damage
Initial k_w = k_w = 10 mD
Final k_w = k_w = 10 mD

Oil Saturation

(Note: These drawings assume the injected oil is perfectly compatible and miscible with the in situ oil - if not, additional damage may be apparent.)

FIGURE 7
EXPANSION OF SWELLING CLAYS

Stabilized - Dehydrated

- OH

Expanded - Hydrated

Na+, K+, Ca++, Mg++

Water Substitution

Tetrahedral Sheet

Octahedral Sheet

FIGURE 8
MECHANISM OF CLAY DEFLOCCULATION

- High salinity
- Stabilized
- Flocculated

- Low salinity
- Destabilized
- Deflocculated
FIGURE 9
EXAMPLE OF FORMATION DAMAGE
MINERAL DISSOLUTION

BEFORE HEATING

AFTER HEATING

Insoluble Fines
Soluble Material (carbonate, dolomite)

Dissolved Material
Reprecipitation
Bridging of Released Insoluble Fines

FIGURE 10
INFLUENCE OF TEMPERATURE ON
RELATIVE PERMEABILITY/WETTABILITY
(Illustrative Example)

Relative Permeability vs. Water Saturation

Kro, Krw Kro, Krw Kro, Krw Kro, Krw
@ 20°C @ 100°C @ 200°C @ 300°C