



Injection Water Quality—A Key Factor to Successful Waterflooding

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Abstract

Poor injection water quality is a prime factor in the reduction in injectivity in many water injection and disposal wells. These reductions in injectivity often result in costly workovers, stimulation jobs and recompletions, or, in many cases, the uncontrolled fracturing of wells by high bottomhole pressures resulting in poor water injection conformance and reduced overall sweep efficiency and recovery.

This paper discusses many commonly occurring water quality issues and how they impact injectivity, including damage due to injection of suspended solids, fines migration, clay swelling and deflocculation, formation dissolution, chemical adsorption and wettability alterations, relative permeability effects associated with the injection of skim oil or grease and the injection of entrained free gas, biologically and bacterially induced damage, formation of insoluble scales and precipitates, emulsification, wax and asphaltene deposition. Screening criteria are presented to allow for a rigorous evaluation of a particular injection water source to investigate potential areas of sensitivity and to attempt to minimize problems associated with impaired injectivity.

Introduction

Water injection processes are utilized throughout the world to dispose of produced aqueous fluids and as a means of increasing the recovery efficiency in many oil reservoirs. A key factor in the success of these operations is contingent on being able to inject a sufficient quantity of the water of interest into the target zone. Injectivity can be restricted by:

- Poor inherent reservoir quality;
- Insufficient pay or contact of the pay zone of interest by the injection well;
- Formation damage effects associated with the actual water injection process.

The subject matter of this paper will concentrate on the topic of injection water quality and how this factor relates to impaired injectivity.

Impaired injectivity causes problems in that it restricts the volume of water which can be injected in a given well (causing potential problems with voidage replacement for a waterflood, or the buildup on surface of a large volume of produced water in a disposal operation). Often downhole injection pressure may exceed fracture pressure causing the initiation and propagation of uncontrolled induced fractures. These fractures may reduce overall efficiency of the waterflood process by lowering areal sweep efficiency and possibly directing injected fluids out of the zones of interest. However, in some cases, fractures may provide con-

nections to zones of interest.

Almost all problems associated with impaired injectivity can ultimately be related back to problems associated with water quality. Potential damage mechanisms which can be associated with water injection processes include:

1. Mechanically induced damage, including:
 - a) Injection of solids,
 - b) Velocity induced damage (fines migration) and settling, where fines are present
2. Injection water/formation rock interactions, including:
 - a) Clay swelling,
 - b) Clay deflocculation,
 - c) Formation dissolution,
 - d) Chemical adsorption/wettability alterations.
3. Relative permeability effects, including:
 - a) Skim oil entrainment,
 - b) Free gas entrainment.
4. Biologically induced impairment, including:
 - a) Bacterial entrainment and growth.
5. Injection water/in situ fluid interactions, including:
 - a) Formation of insoluble scales,
 - b) Emulsification and emulsion blocks,
 - c) Precipitation,
 - d) Wax/asphaltene deposition.

Each of these phenomena will be discussed briefly in this paper. In addition, discussion will be devoted to proper screening and evaluation criteria to minimize problems with water injection quality for a given reservoir application.

Mechanically Induced Damage

Solids Injection

A key factor in gradual reductions in injectivity observed in many water injection and disposal wells can be related to the plugging of the near injection face region by small suspended solids contained in the injection water. These solids could be formation fines and clays (from previously produced formation water), suspended sand, silt or carbonate fines from surface water sources, dead or live bacteria, corrosion products from surface or injection equipment or solids generated in situ from adverse chemical reactions between blended injection fluids or chemical decomposition and degradation of a single source injection fluid.

The severity of plugging and rate of impairment observed will be controlled by:

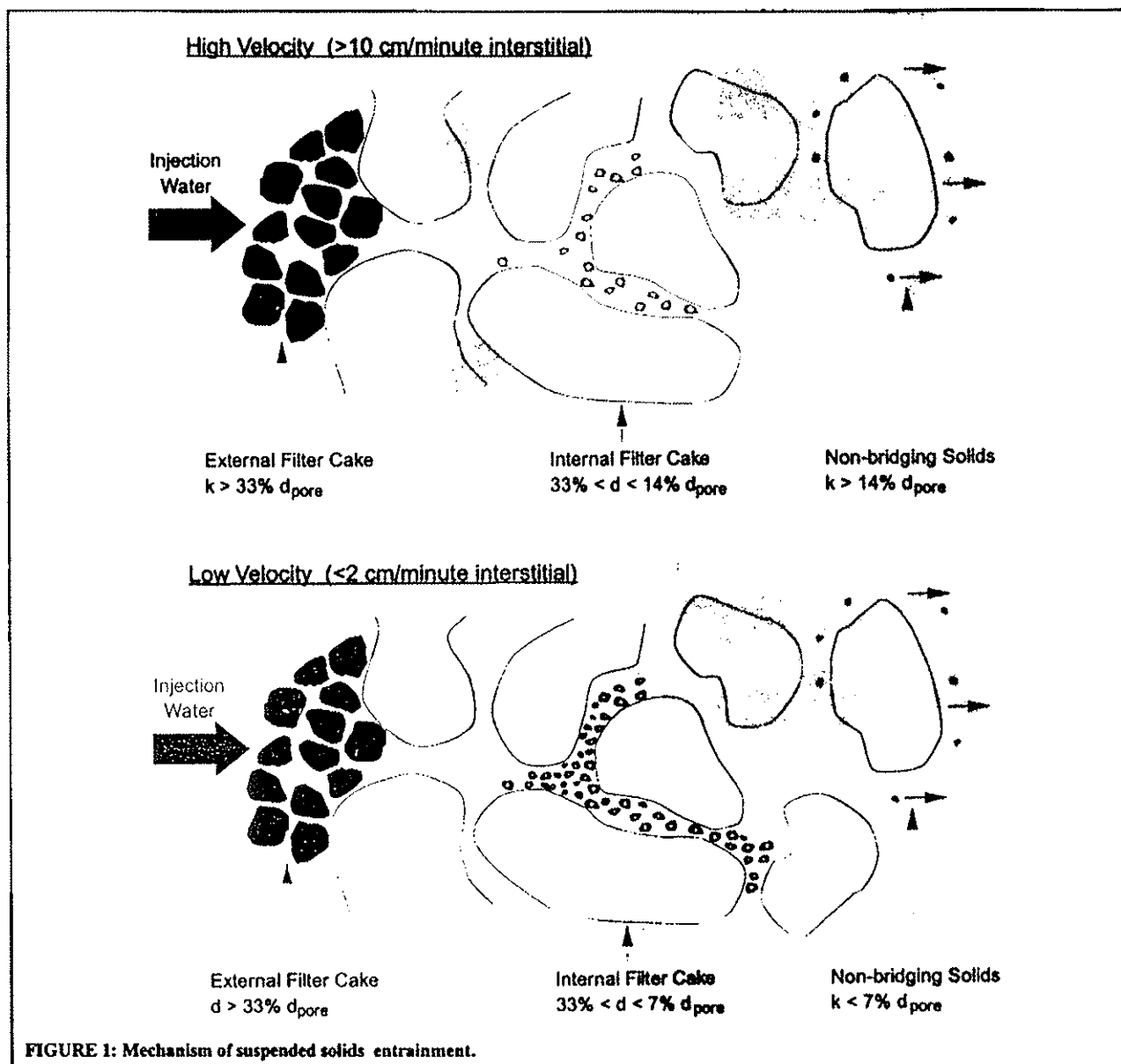


FIGURE 1: Mechanism of suspended solids entrapment.

1. Concentration of suspended solids,
2. Size of the suspended solids,
3. Rate of injection of the suspended solids,
4. Pore size distribution of the formation into which injection is occurring.

Many authors^(1, 5, 13) pioneered early work in this area. Basic rules for water quality postulated by these authors have been expanded upon in recent years^(10, 14, 29, 48, 49).

A schematic of the particulate plugging process in porous media is illustrated in Figure 1. The plugging process is characterized by the entrapment of larger particulates on the surface of the formation interface directly at the wellbore, comprising an "external" filter cake. Smaller particulates invade deeper and can potentially form an "internal" filter cake which may be several centimetres or more from the wellbore. Internal filter cake is generally more damaging due to its relative inaccessibility which reduces the efficiency of conventional mechanical or chemical stimulation treatments. Classical interpretation indicates that, in general, particles larger than 33% of the pore diameter will bridge and form an external filter cake, whereas particles between 14 to 33% of the pore diameter tend to invade deeper into the formation and form an internal filter cake. Particulates smaller than 14% of the pore throat aperture appear to pass through the pores without blockage.

Research indicates that the phenomenon of particle deposition and entrapment is also related to injection velocity. At higher inflow velocities (i.e., greater than 10 cm/min. interstitial rate) the more classical rules of sizing and invasion appear to hold. At lower injection velocities (i.e., less than 2 cm/min.), more damage becomes apparent in the formation of the internal filter cake with respect to smaller particulate sizes. Significant damage in linear flow experiments with particles as small as 7% of the diameter of the pore apertures has been observed at these low flow velocities.

It must also be emphasized that flow into any injection well is a radial flow problem. This means that velocity decreases as the fluid moves out from the wellbore. This indicates that, at some point in the reservoir, velocity will decrease to a point where very small particulates may begin to become entrained in the formation. The severity (if any) of the permeability impairment will depend on the radius of the zone of deposition from the wellbore and the equilibrium damaged zone permeability.

Case studies into the injection of solids and particulates into formations have recently been published^(9, 35).

Velocity Induced Damage (Fines Migration)

Many formations, particularly sandstones, which may contain a higher fraction of loosely attached and mobile clays and detrital rock fragments, exhibit a critical interstitial velocity at which the

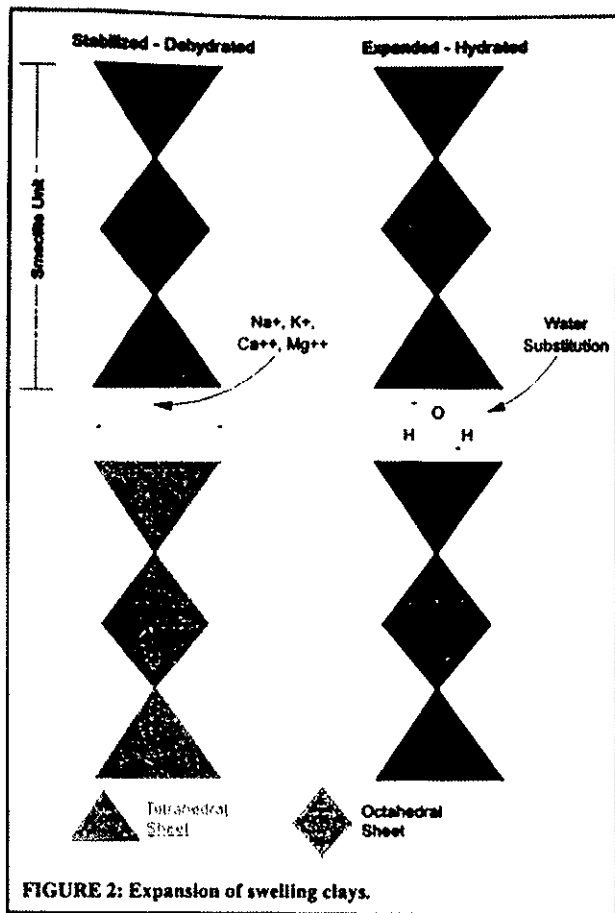


FIGURE 2: Expansion of swelling clays.

mobilization of in situ fines may occur. These fines, if dislodged into the flowing fluid stream by high injection water velocities, may move to pore throat locations where, analogous to injected solids, they may plug and cause reductions in injectivity.

Many authors^(15, 16, 30) have documented phenomena associated with fines migration. Major factors to consider in relation to fines migration include:

1. Fines generally tend to migrate only in the wetting phase. This means that fines mobilization around oil-wet injectors may be less problematic than the equivalent situation in a water-wet formation.
2. Fines migration is aggravated by the turbulence effects associated with simultaneous multiphase flow of both the wetting and non-wetting phases.
3. Near perforation damage and percussion shock can generate in situ fines and aggravate problems associated with near injector damage.
4. Critical velocities are usually determined in the laboratory during linear flow core tests. Translation of these results to complex velocity profiles, which may surround typical perforated injectors, requires the use of near perforation simulation models^(15, 25, 44).

Injection Water/Formation Rock Interactions

Clay Swelling

The phenomenon of clay swelling is well understood and documented in the literature^(6,7,20,24,30,39). Figure 2 provides a schematic illustrating the crystal structure of smectitic clay. A negative charge imbalance in the clay structure is stabilized by the substitu-

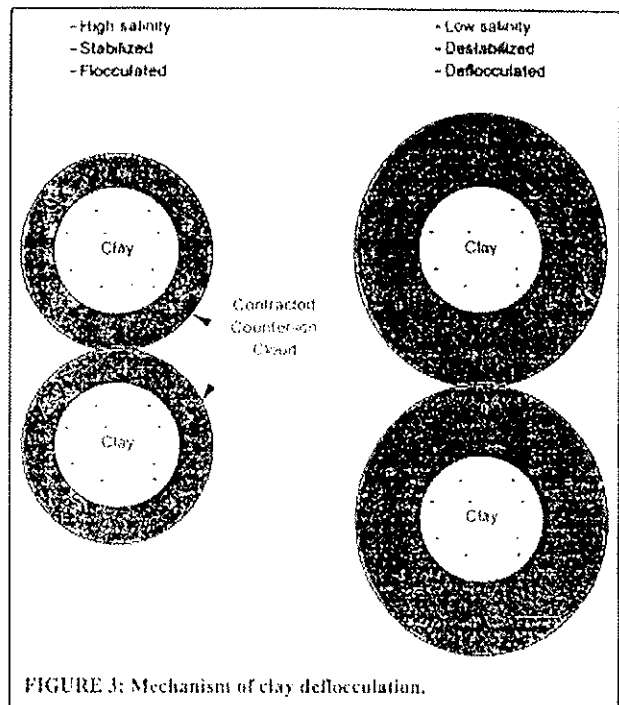


FIGURE 3: Mechanism of clay deflocculation.

tion of a positively charged cation (i.e., Na^+ , K^+ , Ca^{++} , Mg^{++}) into the gap between the individual clay crystals. If an insufficient concentration of these ions is present in the brine contacting the clay (i.e., injection of fresh or low salinity water into a swelling clay rich zone), water, due to its polar nature, can also substitute itself into the gap (Figure 2). The size of the water molecule, in comparison to normally stabilizing cations such as Na^+ or K^+ , causes the physical expansion or swelling of the clay. Depending on the concentration of the clay and its location in the pore system, this expansion can cause severe reductions in permeability. In certain situations, the expansion of the clays can also cause the clay mats or embedded solids to disengage from the pore walls and be transported in the flowing fluid stream to pore throat locations where additional bridging and pore blocking may occur.

Clay Deflocculation

A common oversight in the design of many water injection processes is the assumption that if the formation does not contain a substantial concentration of classical swelling clays (i.e., smectite or mixed layer), it will be insensitive to contact by fresh or low salinity water. The phenomenon of clay deflocculation can be equally damaging in certain situations in reservoirs which contain no "classical" swelling clays and can be caused by abrupt contact with fresh water, sudden salinity changes or shocks or rapid increases in fluid pH levels.

Many authors^(6, 7, 20, 39, 47) in recent years have documented problems associated with clay deflocculation. Clay deflocculation is caused by a disruption of electrostatic forces which are causing the clay to be attracted both to other clay particles and to the pore walls of the porous media under consideration. Most clays possess a net negative charge because of the substitution of low valency cations in the clay lattice structure (i.e., Al^{3+} for Si^{4+} or Mg^{2+} for Al^{3+}). In order to maintain overall electrical neutrality, this negative lattice charge is counterbalanced by a cloud of positive cations that surround the clay structure on or near the clay surface. This diffuse concentration of charge is often referred to as a counter-ion cloud or a diffuse double layer. The size of the diffuse layer is attenuated by diffusion forces if ionic strength in the equilibrium brine is low (i.e., low salinity or fresh water). When mutual repulsion between the charged disperse counter-ion clouds exceeds the attractive Van der Waal forces which are holding the clays in an attracted, flocculated state, the particles disperse or deflocculate. Figure 3 illustrates this phenomenon. Significant

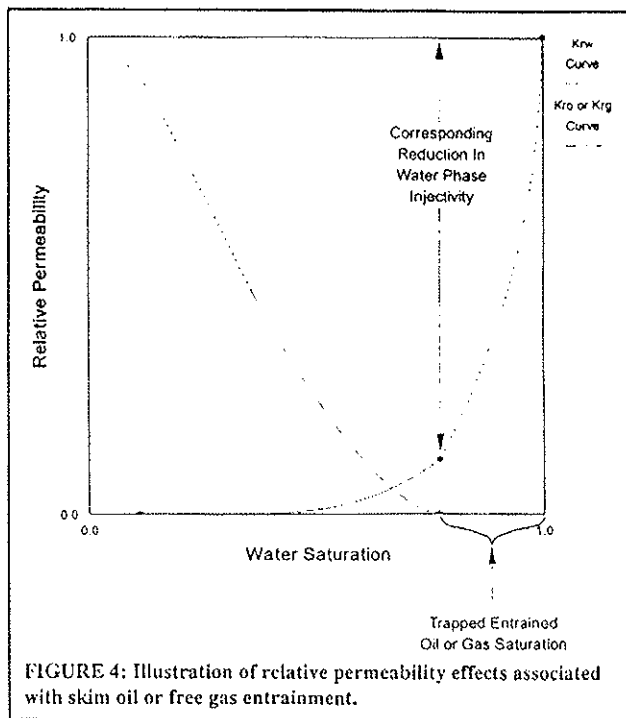


FIGURE 4: Illustration of relative permeability effects associated with skim oil or free gas entrapment.

points to consider with respect to clay deflocculation include:

1. The salinity required to maintain clays in a flocculated state increases with increasing cation exchange capacity (CEC).
2. The flocculating power of cations is a function primarily of the valency of the ion, rather than the specific ion type. For a given valency, flocculation power increases with increased hydrated ionic radius. Therefore:

Monovalent Ions



Divalent Ions



Depending on the clay type, divalent cations can be 50 to 100 times more effective in flocculating clays than monovalent cations. Caution should be taken, however, in that high divalent ion solutions may exhibit other potential damage problems related to the formation of scales or other insoluble precipitates.

3. Abrupt changes in water composition or salinity shocks tend to greatly magnify problems associated with deflocculation due to rapid ion exchange involving surface cations and protons in the water phase. More gradual transitions from formation to injection water over a period of time have been illustrated to reduce or eliminate this problem.
4. Pre-treatment of deflocculation sensitive reservoirs by saturating the near wellbore exchange sites with Ca^{++} has been illustrated to greatly reduce subsequent divalent cation stripping from the injection water (causing a propensity for deflocculation). In some cases KCl or NH_4Cl have also been successfully used as pre-treating fluids prior to water injection.
5. Dispersion of clays is minimized by low pH^(24, 31, 43) and damage due to water shocking can be minimized at pHs less than 2.6. Also, it has been observed that pHs increases substantially during salinity shocks, accompanying the resulting reduction in permeability.

Formation Dissolution

Potential injection zones may include water soluble materials

such as highly hydratable clays, anhydride, halite, etc. Partial or complete dissolution or softening of these minerals by sustained aqueous contact may lead to migration or the release of insoluble fines previously immobilized in an encapsulated state. These particulates, carried by the injection water further into the formation, may cause plugging and blockage.

Chemical Adsorption/Wettability Alterations

Occasionally, re-injected fluids contain chemical additives. Most commonly, these additives include de-emulsifiers and surfactants used to inhibit emulsion formation or allow the separation of the produced crude oil from the total fluid stream. Other materials may include corrosion inhibitors, scale inhibitors, etc. The majority of these chemicals are highly polar and may have a tendency for physical adsorption on both sands and carbonates. The adsorption of these chemicals may cause:

1. Reductions in permeability,
2. Alterations in wettability (generally to a more oil-wet state).

It has been illustrated how the adsorption of phosphonate scale inhibitors damaged North Sea Brent Core⁽¹⁹⁾. In tight formations where the molecular size and charge influence of the adsorbed materials is significant in comparison to pore throat size, the physical adsorption process may also have an impairing effect on permeability.

Near wellbore alterations to a more oil-wet state may not necessarily be detrimental for injection well considerations as they generally cause both an increase in the relative permeability to water and potentially a reduction in the tendency for fines mobilization.

Relative Permeability Effects

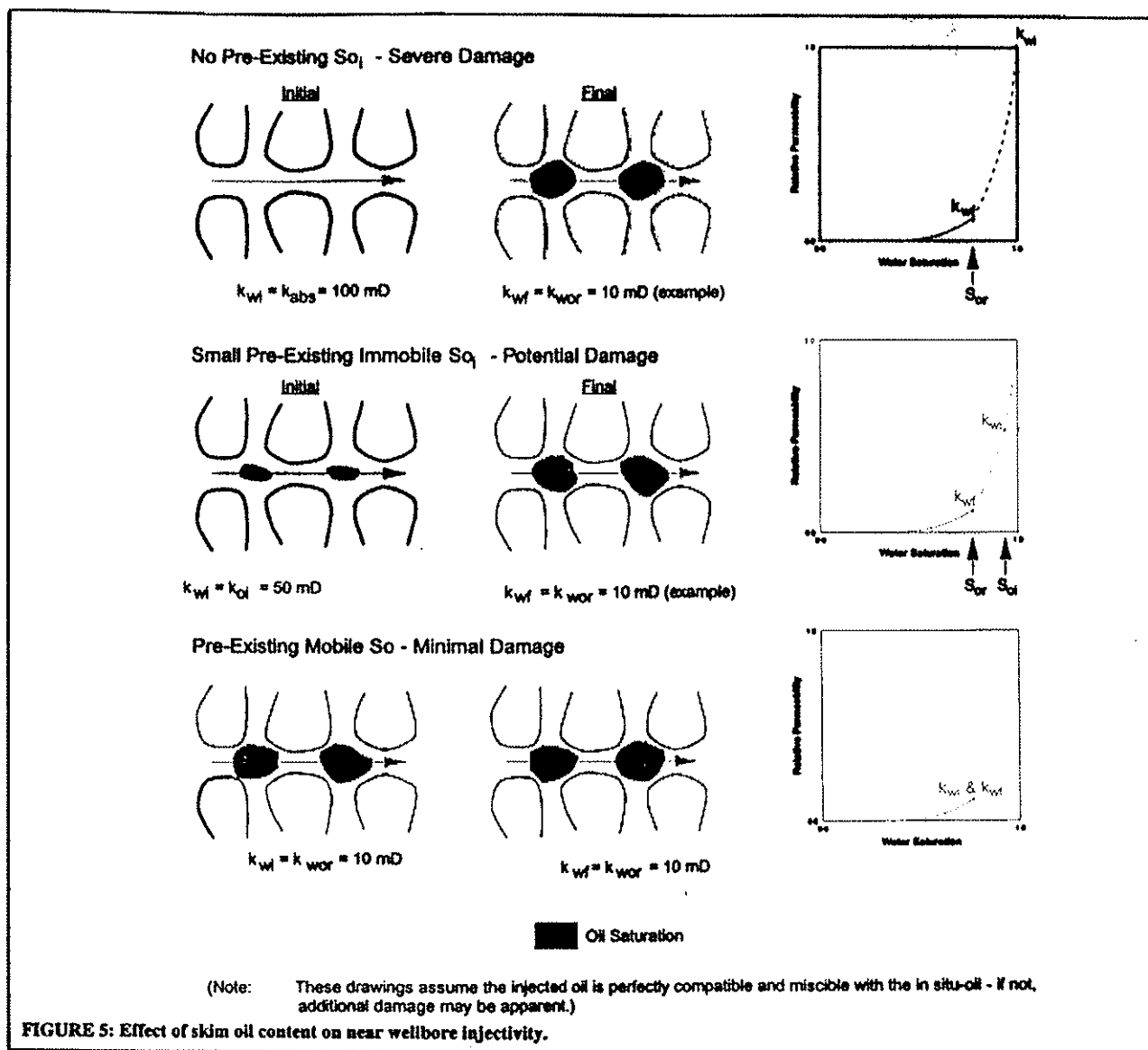
Skim Oil Entrainment

Water injection/disposal projects may be implemented with the water being injected into:

1. Aquifer zones saturated with 100% water (no residual oil saturation),
2. Zones with an oil saturation present, but at an irreducible or sub-irreducible value resulting in no mobility of the trapped hydrocarbon phase,
3. Zones with a mobile oil saturation.

Different problems are associated with the different injection scenarios. Figures 4 and 5 provide an illustration of a typical set of water-oil relative permeability curves and how these relate to the different injection situations. Oil entrapment in injection water and subsequent entrapment is a major source of potential impaired injectivity in situations 1) and 2). This is due to the fact that a sufficiently high saturation of hydrocarbon liquid must be entrapped in the porous media around an injector to ensure that a continuous oil phase with finite relative permeability and mobility is obtained. Prior to this time, the hydrocarbon liquid is merely entrapped as an immobile saturation. Although this saturation is immobile, it may have a profoundly reducing effect on the relative permeability to water (see Figure 4). This effect is particularly pronounced in strongly water-wet sands or carbonates which exhibit very low relative permeability to water, even in the presence of small trapped oil saturations. In these situations, a 10 to 15% trapped irreducible oil saturation could reduce water phase permeability in the affected zone by up to 95%. Continuous injection of suspended hydrocarbons into the formation gradually increases the radius of the zone of affected permeability and, over a period of time, may dramatically reduce injectivity.

If a hydrocarbon saturation is pre-existing in the injection zone, particularly if the saturation is high enough that it is initially mobile, as is the case in many pattern injection waterfloods, then this impairing effect due to hydrocarbon entrapment may be absent or minimal due to the fact that, if the injected oil is compat-



ible and miscible with the in situ fluids, it may simply replace the pre-existing hydrocarbon saturation and the overall effective hydrocarbon saturation may not change.

In many cases, the hydrocarbons contained in the injected water are not simply residual produced oil, but may also contain grease and heavier lubricating oils from pumps or other surface equipment, wax crystals or oxidized crude (if a closed circulating loop is not utilized). These materials generally exhibit high viscosity and, in some cases, limited solubility with existing in situ hydrocarbons. If this is the case, it may be possible to generate a zone of viscous hydrocarbon directly around the injector which could have a substantially reducing effect on permeability, even in a previously hydrocarbon saturated interval.

Gas Entrainment

Entrapment of a critical gas saturation within a porous medium can have a similarly reducing effect to that observed by the entrapment of a residual oil saturation. Although not often considered to be a major problem in typical water injection operations, potential problems may occur if a continual source of low solubility free gas (i.e., air) is entrained in the injected water. This may occur in some situations due to poorly functioning surface equipment or leaks in surface suction lines. Cavitation generated in pumps by air entrainment is also potentially damaging to the injection equipment itself, increasing both corrosion potential and potential injected solids content of the water.

Biologically Induced Impairment

Injection water, irrespective of its source, usually contains bacterial agents. Bacterial problems associated with water injection can be associated with the growth of both aerobic (oxygen requiring) and anaerobic (non O₂ requiring) bacteria in surface equipment, pumps, tubing, downhole equipment as well as within the formation itself. Most types of bacteria grow best in a temperature range from 40 to 70° C (although some types can survive at temperatures well over 100° C). Many deep formations exhibit temperatures too high for bacterial growth; however, in many cases, a zone of cooler formation directly around the injector is established and maintained by the long-term injection of large volumes of low temperature injection water. This may result in severe bacterial growth problems, even in formations which may be considered too warm to be able to support any degree of biological activity.

Many authors^(11, 12, 22, 26, 38, 40, 41, 42) have investigated injectivity, souring and corrosion problems associated with the entrapment and growth of bacteria within porous media. Problems associated with bacterial growth in injection wells can be related to the following areas:

- Plugging,
- Corrosion,
- Toxicity.

Bacteria are sensitive to shear and tend to isolate themselves from fluid shear by the formation of stable biofilms. The biofilms consist of embedded bacterial cells in a matrix of highly viscous

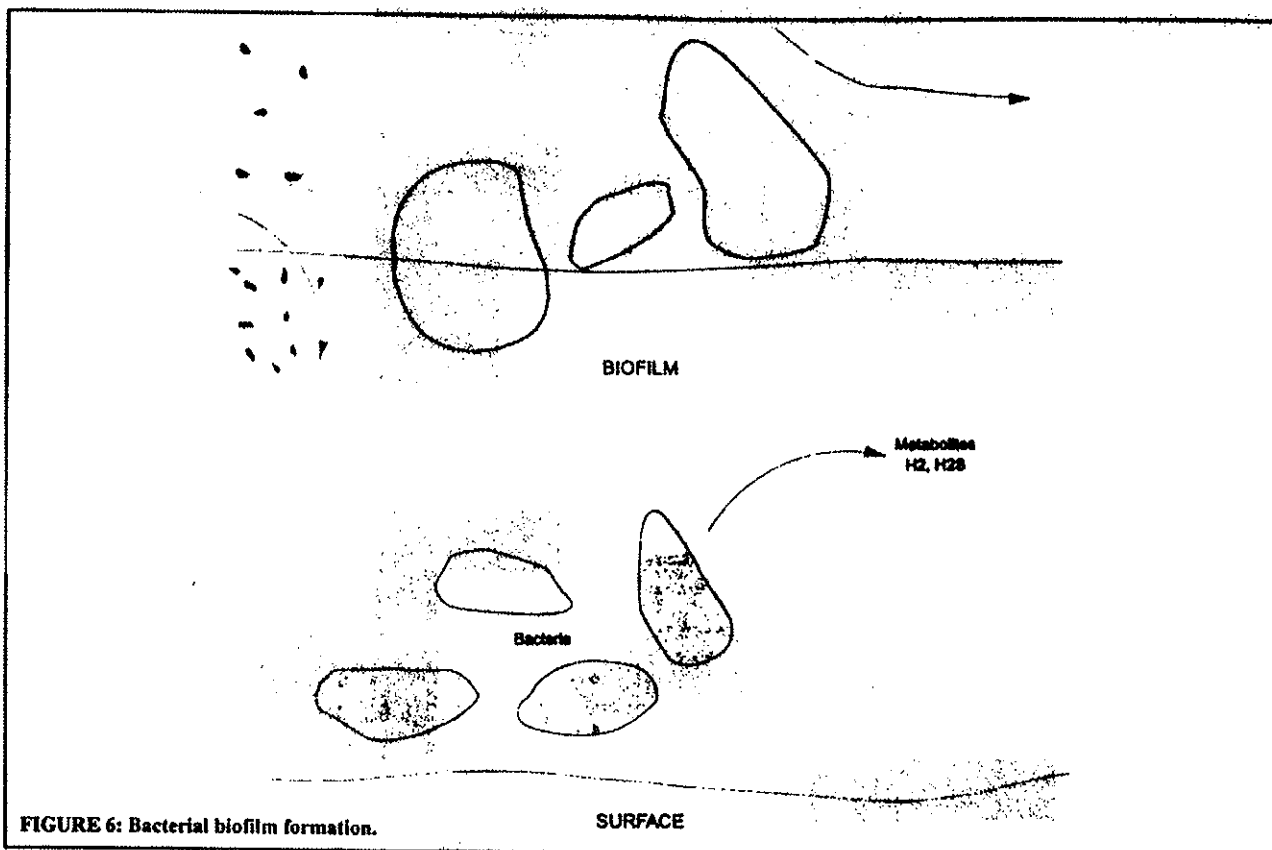
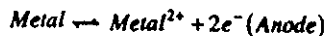


FIGURE 6: Bacterial biofilm formation.

generated exopolysaccharide glycocalyxes. Nutrients and waste products move in and out of the biofilm via substrate and energy transfer. Figure 6 provides an illustration of a typical biofilm.

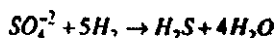
The physical adsorption of the growing biofilm on the surface of the rock matrix can, over a period of time, result in partial or total occlusion of the pore throats in the porous media and a resulting reduction in injectivity. Formations exhibiting smaller pore throats appear to be more rapidly and severely plugged by biofilm generation than higher permeability and porosity media. In addition, the biofilm acts as an active site for the adhesion of other solids or suspended particulates which may be present in the injected water (not unlike flypaper). In this fashion, the two mechanisms of biofilm generation and solids entrainment act together in a synergistic fashion to hasten the decline and severity of the injectivity impairment.

The chemical and physical activity of the microbial community within the biofilm is usually heterogeneously distributed. Metabolites produced from the localized activity of the bacteria can lead to the formation of effective anodes and cathodes at adjoining locations on the surface:



This results in the corrosive pitting which is often associated with the growth of bacteria in downhole or surface equipment or tubing.

Sulphate reducing bacteria (SRB), a particularly troublesome family of anaerobic bacteria commonly found in many oilfield operations and water injection/disposal projects, combine the produced metabolite hydrogen with elemental sulphate to produce toxic and potentially corrosive H_2S :



H_2S is highly soluble in both oil and aqueous solution and is

lethal to humans in low concentrations of only 1,000 ppm. Bacterial agents have been documented to produce H_2S concentrations in excess of 10,000 ppm in produced fluids (i.e., East Wilmington field, Kuparik field, Pembina, etc.).

Water/In Situ Fluid Reactions

Formation of Insoluble Scales

Two major types of scale are commonly encountered in water injection operations, these being carbonate and sulphate based scales. The formation of carbonate based scales [i.e., calcite ($CaCO_3$)] is usually associated with changes in pressure, temperature or pH of the injected fluid as it passes from the surface into the formation. Sulphate scale formation [i.e., gypsum ($CaSO_4$) or barite ($BaSO_4$)] is more often associated with potential incompatibilities between produced and makeup water or blend water and formation water. Carbonate scales, while damaging, are relatively acid soluble in contrast to sulphate based scales which are virtually insoluble in acid and difficult to remove by any conventional means other than mechanical penetration. Complex iron containing scales [i.e., ferrous hydroxide ($Fe(OH)_2$), magnetite (Fe_3O_4), trolite (FeS) and marcasite (FeS_2)] are usually associated with downhole corrosion problems.

Scale problems in injection wells are often associated with:

1. Change in temperature (i.e., carbonate scale solubilities decrease with increasing temperature causing the formation of the scale as temperature increases).
2. Changes in pressure can sometimes affect scale solubility, but, in general, the pressure dependency is weak.
3. Changes in pH. The solubility of carbonate based scales decreases dramatically with increasing pH. This may be caused by removal of acid gases such as CO_2 and H_2S prior to re-injection of produced water.
4. Scale bridges may be sensitive to flow reversals or rate changes that may break down and temporarily increase per-

TABLE 1: Mechanically induced damage screening criteria.

Problem	Solution	Recommended Design
Damage due to solids injection	Determine critical filtration limit to ensure solids will not bridge the average pore throat radius. Recommend a maximum of 7-10% of median pore diameter as a stringent filtration criteria. 25% for non-stringent criteria.	<ol style="list-style-type: none"> 1. Total suspended solids on injection brine. 2. Size distribution of suspended solids. 3. Formation pore size distribution by Hg injection, petrographic image analysis or thin section analysis. 4. Critical filtration flow through test in porous media to verify adequate filtration.
Velocity induced damage	Ensure that critical velocity for water injection is not exceeded.	<ol style="list-style-type: none"> 1. Ascertain formation wettability (contact angle, Amott test, combined Amott/USBM). 2. Critical velocity test to determine velocity sensitivity. 3. Near perforation numerical simulation to extend linear flow results back to complex near perforation pattern flow.

meability with increases in rate. This effect appears to be more pronounced in higher permeability formations.

In some cases, scale problems can be controlled by the modification of the water blend ratio or, if practical, alteration of the water source. In many cases, chemical scale inhibitors or pH reducing agents must be utilized in order to inhibit scale formation. The proper evaluation of scaling potential and correct selection of an inhibitor is a complex process which is beyond the scope of this paper. Extensive work in this area has been presented^(3, 17, 21, 23, 27, 32, 33, 36, 37, 46, 50),

- Water composition,
- Oil composition,
- Contaminants in injection water (i.e., surfactants or surface active agents),
- Injection rate and degree of turbulence induced in situ in the porous media by specific pore geometry.

In general, lower gravity oils (< 30° API) and waxy crudes tend to be more susceptible to emulsification problems, but emulsification has also been observed in higher API gravity conventional oils in certain situations.

Emulsification

Various authors^(2, 4, 8, 28, 34) have discussed the formation of emulsions caused by the simultaneous flow of oil and water in porous media. The generated emulsions may be of two types, high viscosity water in oil (oil external) emulsions or low viscosity oil in water (water external) emulsions. The water in oil emulsions tend to be the most problematic due to their high apparent viscosity (sometimes up to two orders of magnitude greater than the in situ oil) and ability to significantly impair fluid flow in the near injector region. In situ emulsification is related to:

Precipitation

Many injection waters can react adversely with in situ brines and form insoluble carbonate, sulphate or iron based precipitates which can internally plug within the pore system. This problem is especially apparent when injecting sulphate rich brines (i.e., sea-water) into divalent ion rich formations. Proper understanding of the potential for precipitation can assist in adequate injection water design criteria, including the use of techniques such as membrane filtration to remove potentially adverse ions with high precipitation potential.

TABLE 2: Injection water-formation rock Interaction screening criteria.

Problem	Solution	Recommended Design
Damage due to clay swelling	Determine critical salt concentration to inhibit swelling.	<ol style="list-style-type: none"> 1. XRD/SEM/thin section to determine location and abundance of clay. 2. Critical salinity test to evaluate minimal salinity required to inhibit clay swelling - or 3. Computer expert system simulation if lithology matching rock types available in historical data base.
Damage due to clay deflocculation	Determine ion type and valency to inhibit clay deflocculation.	<ol style="list-style-type: none"> 1. XRD/SEM/thin section analysis to determine location and abundance of clay. 2. Horizontal and vertical salinity and cation tests to investigate minimum ion content and valency content to inhibit clay deflocculation. 3. Computer expert system simulation if lithology matching rock types available in historical data base.
Formation Dissolution	Modify brine composition to slow/eliminate dissolution.	<ol style="list-style-type: none"> 1. Static/dynamic core flow tests to investigate dissolution effects and effects of brine contact on rock geomechanical strength.
Chemical Adsorption/Wettability Alterations	Modify inhibitors/additives to minimize adsorption or wettability altering effects.	<ol style="list-style-type: none"> 1. Static/dynamic core flow tests to investigate degree of adsorption and effect on water permeability as a function of exposure time and throughput volume.

TABLE 3: Relative permeability effect screening criteria.

Problem	Solution	Recommended Design
Skim oil/grease carryover	Surface treatment to reduce skim oil/grease content (<5 ppm general guideline)	<ol style="list-style-type: none"> 1. Measure injection water oil and grease content. 2. Investigate effect of carryover oil entrapment in porous media via displacement testing to quantify severity of potential damage.
Free gas entrainment	Modify surface equipment to eliminate free gas entrainment.	<ol style="list-style-type: none"> 1. Evaluate injection water for evidence of free gas entrainment. 2. Investigate magnitude of critical gas saturation and potentially reducing effect on water injectivity in porous media via dynamic and displacement testing.

TABLE 4: Biological impairment screening criteria.

Problem	Solution	Recommended Design
Potential Biological Damage	Investigate bacterial sources and institute a biological control program to avoid the injection of live bacteria and/or nutrients into the formation and to kill existing downhole bacterial colonies.	<ol style="list-style-type: none"> 1. Evaluate if conditions downhole are appropriate for bacterial growth, T<90°C, neutral pH conditions, etc. 2. Evaluate bacterial content and types in injection fluids. 3. Using backflow of injection and hydrogenase field titration techniques, determine current level of field biological activity. (After Horacek (1992)). 4. Investigate biocide concentrations necessary to maintain low level bacterial activity in injected fluids. 5. Investigate sterilization techniques (i.e. - oxidants) to kill existing downhole bacterial colonies and reduce in-situ biofilms to enhance injectivity. This is generally done through a combination of controlled contact and dynamic core flow experiments.

TABLE 5: Water in situ fluid interaction screening criteria.

Problem	Solution	Recommended Design
Scale Formation	Modification in injection water composition or selection of appropriate compatible scale inhibiting agent.	<ol style="list-style-type: none"> 1. Extended water analysis. 2. Evaluate scale potential at surface and downhole conditions using laboratory or computer simulation techniques. 3. If scaling potential present, evaluate effect of possible changes in injection water composition or treatment to mitigate scale formation. 4. Investigate chemical scale inhibitors through compatibility and coreflow test techniques to ascertain their effectiveness. 5. Investigate chemical (i.e. acid) stimulation techniques for the removal of carbonate based scales. 6. Investigate pH based techniques (i.e. acid gas dissolution, etc.) for the inhibition of scale formation.
In-situ emulsification	Modification of brine composition, reduction of injection rate to reduce in-situ turbulence or use of chemical de-emulsifiers.	<ol style="list-style-type: none"> 1. Evaluate potential for both spontaneous and turbulence induced emulsification. 2. Evaluate water compositional/pH effects on emulsion stability. 3. Evaluate rate effects in porous media on emulsion formation to determine if a critical interstitial velocity exists for emulsion formation. 4. Evaluate de-emulsifier via in-situ core stimulation to determine effectiveness in breaking/inhibiting the formation of in-situ emulsions and potential de-emulsifier-rock adverse interaction.
Precipitation of insoluble solids via water-water incompatibilities	Modification of brine composition, blend ratio or use of chemical inhibitors to prevent precipitation.	<ol style="list-style-type: none"> 1. Extended water analysis on in-situ water, produced water and blend water. 2. Conduct multiratio compatibility testing (in laboratory or via computer modelling techniques) to observe propensity for precipitate formation. 3. Evaluate inhibitor or compositional modification techniques in the lab or via dynamic coreflow techniques to ascertain effectiveness.
Wax/asphaltene deposition	Modify near wellbore conditions to inhibit formation of wax/asphaltenes.	<ol style="list-style-type: none"> 1. Measure in-situ oil cloud and pour points, white wax and black wax content. 2. Investigate temperature limits for natural asphaltene deposition. 3. Investigate minimum temperature required to inhibit wax/asphaltene formation or possible suppression of this temperature via the use of chemical inhibitors.

Wax/Asphaltene Precipitation

Wax and asphaltene deposition problems are not normally associated with impaired water injectors, but they can occur due to localized reductions in temperature caused by the injection of large volumes of cool injection water. This problem is most pronounced in injection into oil saturated zones where the oil cloud point is close to original reservoir temperature. Certain oils also may have a propensity to precipitate asphaltene particles as temperature is reduced which may also potentially impair injectivity. The literature⁽⁴⁵⁾ provides further documentation on these phenomena.

Criteria for Injection Water Screening

It can be clearly seen that a multitude of phenomena may potentially be causing reductions in injectivity in a given impaired well. In many cases, the actual mechanism of impairment is not simply a single item, but may be a combination of several different factors. The following section presents general criteria for water screening to attempt to avoid many of the problems previously discussed and outlines commonly utilized techniques for optimizing injection water quality.

Tables 1 to 5 provide a summary of problem statements, proposed criteria for solution and recommended procedures for water screening/design to mitigate the stated problems associated with mechanically induced damage, injection water-rock incompatibilities, relative permeability effects, biological damage and fluid-fluid interactions respectively. These tables provide general screening criteria which need to be considered with respect to ensuring acceptable water quality is obtained for any water injection or disposal operation.

Conclusions

This paper has outlined a number of potential areas of concern with respect to injection water quality for water injection or disposal wells and solutions to these problems are presented in the attached tables. It has been illustrated that the majority of problems associated with impaired injectivity can usually be related directly or indirectly back to problems associated with water quality. Reductions in injectivity can generally be related to a combination of water quality problems, rather than a single problem. A proper understanding of the quality of the injected water, including its composition, contaminants and suspended solids it may contain, must be coupled with a detailed understanding of the nature of the target formation, the fluids it contains and the conditions of injection in order to effectively be able to objectively evaluate problems with water quality. Screening guidelines and criteria have been presented which will allow for a rigorous evaluation of most of the commonly occurring water quality problems.

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Douglas Bennion received his Bachelor's degree from the University of Oklahoma, and his Masters and Ph.D. from Pennsylvania State University, all in petroleum engineering. He worked for Mobil Oil in Canada for six years between degrees and taught at the University of Calgary in the Department of Chemical and Petroleum Engineering for 21 years. In 1986, he retired from the University of Calgary and became C.E.O. for Hycal Energy Research Laboratories Ltd. He has guided Hycal to become an international company currently working in Europe, Asia, Africa, Australia and North and South America, with branch offices in the U.S.A. and South America.



Brent Thomas holds a doctorate in chemical engineering. He has worked on enhanced oil recovery applications for the last 20 years, including gas injection, chemical flooding, solids precipitation and thermal applications. He is the author of over 120 technical papers and has lectured extensively worldwide. He is presently vice president of Hycal Energy Research Laboratories Ltd.



Ron Bletz completed his B.Sc. in petroleum engineering from the University of Wyoming in 1987 and has worked extensively in the area of formation damage and reservoir optimization. Formerly manager of engineering at Hycal, Mr. Bletz is now employed as a field engineering manager at Gulf Canada Resources.