

# Formation Damage: Origin, Diagnosis and Treatment Strategy

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## 14-1. Introduction

Formation damage reduces the well production or injection capacity, and the removal of damage is one of the major goals of petroleum engineers. This chapter identifies and quantifies formation damage and includes ideas on treatment strategy. It is important to note that not all types of formation damage require a removal treatment. Some types of damage will clean up during production, and others can be removed by changes in operating practices. In addition, some producible impairment is misconceived as “damage,” when it is actually poor well design that can be remedied with operational changes. Classifying damage correctly requires more than experience in the chemistry or physics of damage. A thorough knowledge of field operating conditions is essential, and correct identification is critical to successful removal.

The terms formation damage and skin effect damage have been applied to describe many well productivity impairments (Krueger, 1986; Porter, 1989). Damage can be anything that obstructs the normal flow of fluids to the surface; it may be in the formation, perforations, lift system, tubulars or restrictions along the flow path. Formation damage specifically refers to obstructions occurring in the near-wellbore region of the rock matrix. Other types of damage can be identified by location. Figure 14-1 shows some common types of damage; these production impairments can occur anywhere in the production system, from the wellbore to perforations and into the formation. Such a distinction is not usually made because seldom are most of the plugging phenomena located in only one part of the flow system. The importance of determining the causes of the observed damage cannot be understated. Only by knowing the damage mechanism, its location and how it is affecting flow can an effective treatment strategy be developed. There have been significant improvements over the past few years in recognizing and describing the various types of damage, and

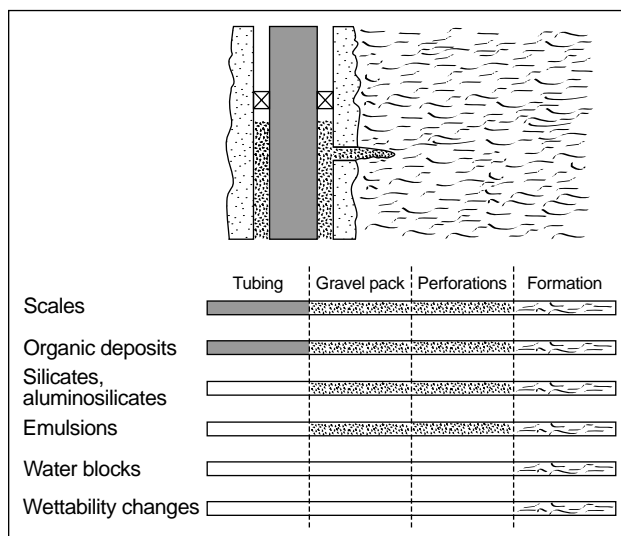


Figure 14-1. Location of various types of damage.

many publications have appeared on the subject (Allen, 1973; Hurst, 1973; Leon, 1973; Sands, 1973; Christian and Ayres, 1974; Bruist, 1974; Shaw and Rugg, 1974; Black and Rike, 1976; Maly, 1976; Sparlin and Hagen, 1983; Krueger, 1988; Amaefule *et al.*, 1998; Adair and Smith, 1994; Beadie, 1995; Reid, 1996).

The goal of this chapter is to give a broad view of formation damage. Damage characterization is the key to proper design of removal treatments. A general description of the various damage types and mechanisms is presented, followed by a discussion of the origins of damage resulting from natural causes and well operations. The testing required to determine the presence of formation damage and its characterizations are also discussed. Treatment strategies for removing formation damage are presented.

## 14-2. Damage characterization

Damage characterization is the “history” in damage removal. The search for the identity of the damage

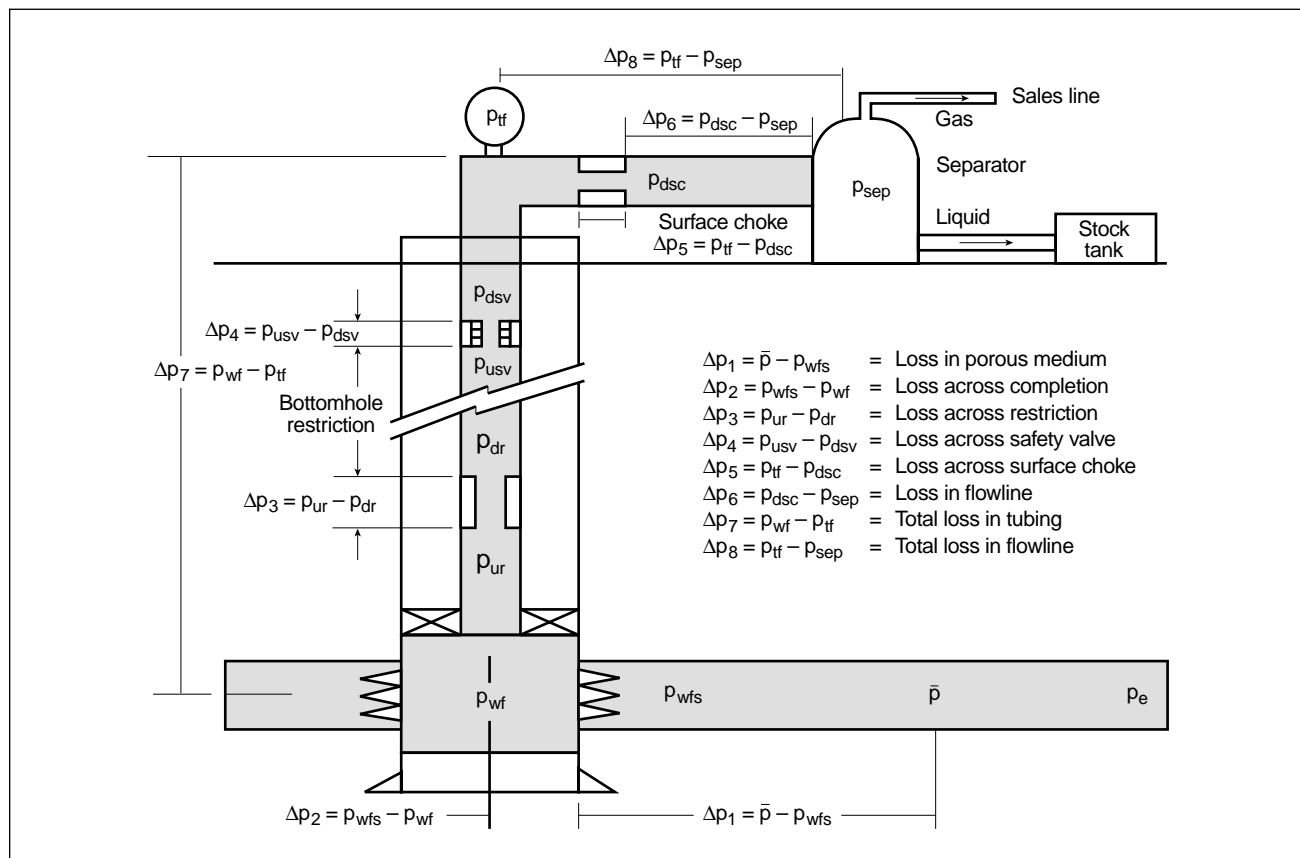
begins in the production and development history of the well and even neighboring wells. Drilling records, completion design, offset well performance and/or operator experiences and past treatment records are all sources of information. The objective is to identify the location and types of damage that may be a problem. Although damage is usually considered a singular problem, multiple occurrences of damage are common, some with interfering removal treatments.

Formation damage identification and investigation include

- types of damage
- location of damage
- extent and screening of damage
- effect of damage on well production or injection.

### 14-2.1. Pseudodamage

Chapter 1 demonstrates the impact of skin effect reduction on well performance. Chapter 2 describes techniques for estimation of the total well skin effect, which are accomplished primarily through well testing. As discussed in Chapter 1, not all skin effect is due to damage. There are other contributions that are not related to formation damage. These pseudoskin effects are generally mechanical, resulting from obstructions to flow or because of rate- and phase-dependent effects. Their values must be subtracted from the total skin effect to estimate the skin effect associated with formation damage (Petersen *et al.*, 1984). One way to accomplish this is to use NODAL production system analysis to develop an inflow performance relationship (IPR) curve specific to the well. NODAL analysis allows optimizing production conditions for a given well and thus optimizing the well completion (Fig. 14-2).



**Figure 14-2.** Pressure losses in the producing system of a flowing well.  $p_{wf}$  = bottomhole flowing pressure,  $\bar{p}$  = average pressure,  $p_e$  = reservoir pressure,  $p_{dr}$  = downstream restriction pressure,  $p_{dsc}$  = pressure downstream of the surface choke,  $p_{dsv}$  = pressure downstream of the safety valve,  $p_{sep}$  = separator pressure,  $p_{tf}$  = tubing flowing pressure,  $p_{ur}$  = upstream restriction pressure,  $p_{usv}$  = pressure upstream of the safety valve,  $p_{wfs}$  = wellbore sandface pressure.

### 14-2.2. Pseudoskin effects and well completion and configuration

Positive pseudoskin effects can result from the well completion design or well configuration. Problems include

- limited entry to flow (Odeh, 1968; Jones and Watts, 1971; Saidikowski, 1979)
- off-center wells (Denson *et al.*, 1976; Fetkovitch and Vienot, 1984)
- low perforation density, short perforations or incorrect phasing (Hong, 1975; Locke, 1981; McLeod, 1983)
- mechanical flow restrictions
- mismatched or inadequate fluid-lift systems
- laminated reservoirs (shale streaks).

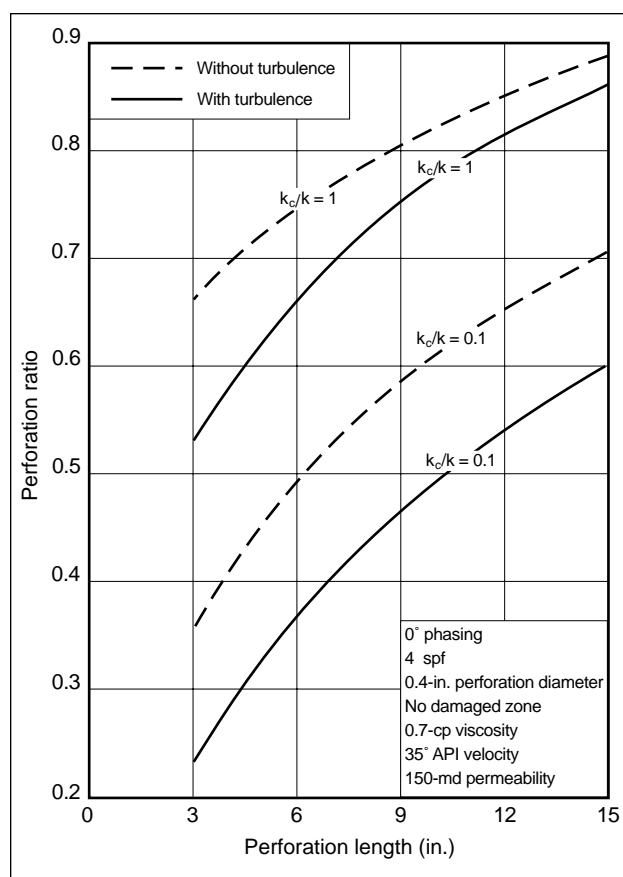
A negative pseudoskin effect always exists in deviated wells; it is a function of the deviation angle and the formation thickness (Cinco-Ley *et al.*, 1975).

- Pseudoskin and rate-and-phase effects

Operating pressures and production conditions may induce additional pressure drops or pseudoskin effects. Producing a well at a high flow rate can cause turbulent flow in perforations and sometimes in the formation (Fig. 14-3) (Tariq, 1984; Himmatramka, 1981). The corresponding positive pseudoskin effect is proportional to the flow rate above a minimum threshold value. Below this critical value, this pseudoskin effect is suppressed (Jones *et al.*, 1976). The problem increases with gravel-packed perforations (for sand control) and for high-production-rate gas wells in general. The problem becomes particularly acute for the fracture-to-wellbore connection in deviated wells with fractures at an angle to the wellbore.

Scale precipitation in and around the perforations can progressively modify the reservoir flow conditions, increasing the pressure drop and changing the flow regime from Darcy to non-Darcy and creating a turbulence pseudoskin effect (Meehan and Schell, 1983). This is in addition to the actual damage skin effect.

Producing a well below the bubblepoint pressure may cause a positive pseudoskin effect as liquids condense around the wellbore, impeding flow (Blackmer, 1982; Hinchman and Barree, 1985; Economides *et al.*, 1989). This is a relative permeability phenomenon, with free gas concentrating



**Figure 14-3.** Effect of turbulence and a compacted zone (90% permeability reduction) on the productivity ratio (Tariq, 1984).  $k$  = permeability,  $k_c$  = damaged zone permeability.

around the wellbore causing a reduction to the relative permeability to oil. A similar but more severe problem can happen when producing gas condensate wells below the dewpoint. Both phenomena manifest as positive pseudoskin effects.

In unconsolidated sand reservoirs, a flow-rate-dependent skin effect can be caused by modifications of the sand arches around the perforations. Abrupt variations of skin effect and concomitant sand releases occur above the threshold flow rate value (Tippie and Kohlhaas, 1974).

- Other pseudodamages

Other mechanical causes of production impairment are

- tubing collapse or restriction by lost objects or any adhering deposit
- collapsed perforations in formations where the formation competence has been overestimated

(Antheunis *et al.*, 1976; Chenevert and Thompson, 1985)

- poor isolation between zones resulting from poor cementation of the annulus—e.g., oil invasion of a gas cap significantly reduces the relative gas permeability, mixing oils of two different zones may cause paraffin and asphaltene precipitation, or water invading an oil-bearing zone reduces the relative permeability to oil (water block), may create emulsions and may cause clay and scale problems. Stimulation treatments that do not achieve required results and that cause additional damage may have been sabotaged by bad isolation (Abdel-Mota'al, 1983).
- poor design of gas lift systems—small-diameter tubing, unadapted operating gas lift pressure (Blann and Williams, 1994), improper valve design and high surface backpressure (Jones and Brown, 1971).

## 14-3. Formation damage descriptions

Once mechanical pseudoskin effects are identified, positive skin effects can be attributed to formation damage. Formation damage is typically categorized by the mechanism of its creation as either natural or induced. Natural damages are those that occur primarily as a result of producing the reservoir fluid. Induced damages are the result of an external operation that was performed on the well such as a drilling, well completion, repair, stimulation treatment or injection operation. In addition, some completion operations, induced damages or design problems may trigger natural damage mechanisms.

Natural damages include

- fines migration
- swelling clays
- water-formed scales
- organic deposits such as paraffins or asphaltenes
- mixed organic/inorganic deposits
- emulsions.

Induced damages include

- plugging by entrained particles such as solids or polymers in injected fluids
- wettability changes caused by injected fluids or oil-base drilling fluids

- acid reactions
- acid by-products
- iron precipitation
- iron-catalyzed sludges
- bacteria
- water blocks
- incompatibility with drilling fluids.

Each of these mechanisms is addressed in detail in the following sections. Damage from iron precipitation and iron-catalyzed sludges is discussed elsewhere in this volume.

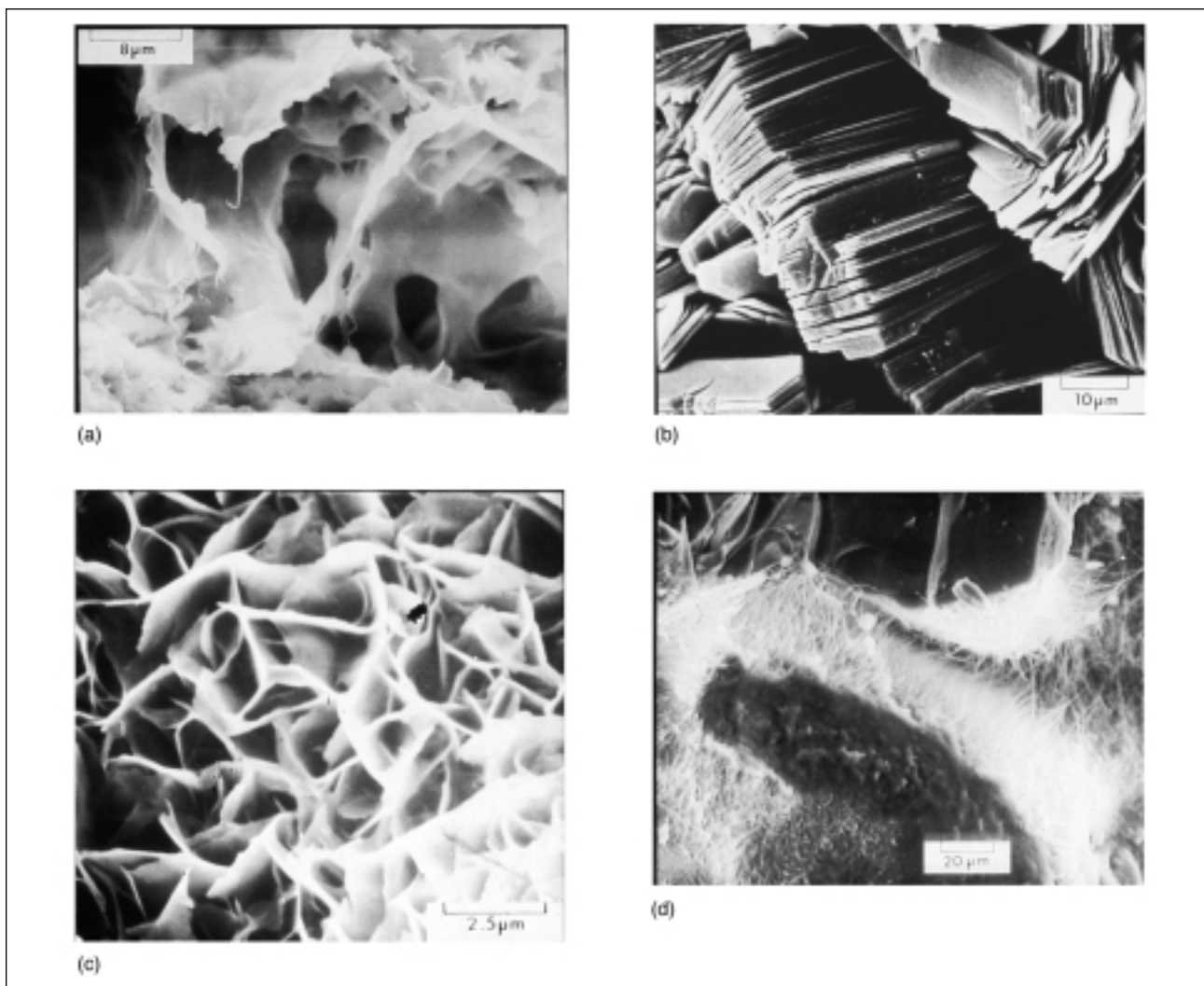
### 14-3.1. Fines migration

Formation damage can occur as a result of particle migration in the produced fluid. The particles can bridge across the pore throats in the near-wellbore region and reduce the well productivity. When the damaging particles come from the reservoir rock, they are usually referred to as fines. Migrating fines can be a variety of different materials, including clays (phyllosilicates with a typical size less than 4  $\mu\text{m}$ ) and silts (silicates or aluminosilicates with sizes ranging from 4 to 64  $\mu\text{m}$ ). Kaolinite platelets (Fig. 14-4) are thought to be some of the more common migratory clays. Table 14-1 lists the major components of various clays and fines particles. The table also lists the surface area of the clays, one of the indicators of how quickly the clay can react with a reactive fluid (Davies, 1978). Damage from fines is located in the near-wellbore area, within a 3- to 5-ft radius. Damage can also occur in a gravel pack (e.g., silicates and aluminosilicates in Fig. 14-1).

The distinction between types of clays depends more on the arrangement of the atoms in their crystalline structure rather than any major difference in

**Table 14-1. Major components of various clay and fines particles.**

Particle Mineralogy	Major Components	Surface Area ( $\text{m}^2/\text{g}$ )
Quartz	Si, O	0.000015
Kaolinite	Al, Si, O, H	22
Chlorite	Mg, Fe, Al, Si, O, H	60
Illite	K, Al, Si, O, H	113
Smectite (montmorillonite)	Na, Mg, Ca, Al, Si, O, H	82



**Figure 14-4.** Photomicrographs of (a) pore-filling smectite sheets, (b) “books” of kaolinite platelets in a pore space, (c) honeycomb growth of chlorite on a sand grain and (d) hairs of illite extending from a sand grain.

chemical formula. These structural differences determine the surface area exposed to the reservoir fluids for each clay. Clay reactivity is a function of this surface area. The location of the clay is also critical to its reactivity. Authigenic clay is in a pore throat as fill or as a lining (i.e., grown in the pore from minerals in the connate water) (Wilson and Pittman, 1977). Authigenic clays have a large amount of surface area exposed in the pore and can be reactive. Detrital clay is part of the building material in the original matrix. Detrital clays are usually less reactive than authigenic clays because they have less surface area in contact with the fluids in the pore. The vast majority of detrital clays usually cannot be contacted by sufficient volumes of reactive fluids to cause problems. Clay may also act as a cement,

holding the matrix grains together. As a binder or cement, clay may react with fluids such as acid and water to disaggregate the formation. If the clay cement is shielded by a quartz overgrowth, as is common in many sandstones, the clay will not be reactive.

Only authigenic clays, unprotected clay cements and the few detrital clays on the pore boundary are worth consideration as potential damage mechanisms. Scanning electron microscopy (SEM) is generally used to determine clay type; however, recognition of the type of clay should not be staked entirely on an SEM analysis. Focused dispersive X-ray analysis is much more accurate. Even after identification of the clay, laboratory core flow tests are typically required to determine if the clays within the

flow channels are reactive with a given fluid. The common clays that account for most of the real and perceived clay problems are kaolinite, smectite (montmorillonite), illite and chlorite. The structures of kaolinite, smectite, illite and chlorite are shown in Fig. 14-4. Simply because the clay is in the rock does not mean that the clay is reactive.

### 14-3.2. Swelling clays

Clays may change volume as the salinity of the fluid flowing through the formation changes. Several authors have dealt with clay swelling in sandstones, showing either ion exchange, movement or critical salt concentration triggering clay dispersion (Azari and Leimkuhler, 1990b; Jones, 1964; Khilar and Fogler, 1983; Mungan, 1968; Sharma *et al.*, 1985; Priisholm *et al.*, 1987). Changes in formation permeability resulting from the alteration of clay are due to the amount, location and type of clay minerals within the formation. The total quantity of clay inside the formation is a misleading indication of potential changes to permeability. It is the arrangement of the clay, its chemical state at the moment of contact and the location of the clay with respect to the flowing fluids that are responsible for the changes. Predicting the response of a clay to water flow is almost impossible without testing.

The most common swelling clays are smectite and smectite mixtures. Smectite swells by taking water into its structure. It can increase its volume up to 600%, significantly reducing permeability. If smectite clay occupies only the smaller pore throats and passages, it will not be a serious problem; however, if it occupies the larger pores and especially the pore throats, then it is capable of creating an almost impermeable barrier to flow if it swells.

Clays or other solids from drilling, completion or workover fluids can invade the formation when these particles are smaller than the pore throat openings. Any subsequent increase in flow rate through the invaded zone will force a high concentration of particles into the rock matrix.

### 14-3.3. Scales

Scales are water-soluble chemicals that precipitate out of solution in response to changes in conditions or the mixing of incompatible waters. They can be

present in the tubing, perforations and formation (Fig. 14-1). The most common oilfield scales are calcium carbonate, calcium sulfate and barium sulfate. Water-formed scale deposits are among the most troublesome damage problems (Cowen and Weintritt, 1976). Scale usually consists of precipitates formed from mixing incompatible waters or upsetting the solution equilibrium of produced waters. A water that may be stable under reservoir conditions may become supersaturated with an ion when the pressure decreases, which allows carbon dioxide (CO<sub>2</sub>) outgassing, or the temperature changes. The supersaturated solutions react by precipitating a compound from solution. The deposition of scale is influenced by pressure drop, temperature, dissolved gases, flow viscosity, nucleation sites and metal type—in short, anything that upsets the solution equilibrium.

The following scales are among the most troublesome.

- Calcium carbonate or calcite (CaCO<sub>3</sub>)  
CaCO<sub>3</sub> is usually formed when the pressure is reduced on waters that are rich in calcium and bicarbonate ions. The deposition can be affected by CO<sub>2</sub> outgassing, which raises the pH value and makes the high concentrations of calcium unstable.
- Gypsum (“gyp”)  
Gypsum may be the most common sulfate scale in the oil industry (Cowen and Weintritt, 1976). With a chemical structure of CaSO<sub>4</sub> · 2H<sub>2</sub>O, it shares a similar composition to the hemihydrate CaSO<sub>4</sub> · ½H<sub>2</sub>O, commonly called plaster of paris or by its mineral name, bassonite. It is also formulaically similar to the evaporite mineral anhydrite (CaSO<sub>4</sub>).
- Barium sulfate (BaSO<sub>4</sub>)  
BaSO<sub>4</sub> is a less common form of sulfate deposit, but it causes extensive problems. Almost any combination of barium and sulfate ions causes precipitation. It is difficult to remove, as it is not significantly soluble in acids and solvents unless it is finely ground or the structure is interrupted with impurities such as carbonate scale. Like calcium sulfate, barium sulfate is usually thought to be a product of mixing incompatible waters, with precipitation accelerated by pressure drop, outgassing or turbulence. Some barium sulfate is radioactive; this is part of naturally occurring radioactive

material (NORM) scales. The radioactivity results from a concentration of uranium in the lattice of the scale. The buildup of radioactive scale can be monitored using a gamma ray logging tool. Care must be exercised when analyzing well debris to avoid mislabeling barite ( $\text{BaSO}_4$ ) from drilling mud residue as barium sulfate scale.

Strontium sulfate or celestite ( $\text{SrSO}_4$ ) is a common substitute in the barium sulfate crystal lattice. Strontium scale can be associated with radioactive scale (NORM). It may be more soluble than barium sulfate in chemical remover systems.

- Iron scales

Iron scales such as iron carbonate and iron sulfide can be extremely difficult to remove. They are usually seen in wells that have both a high background iron count and a tendency to precipitate calcium carbonate. Iron sulfide scales react according to their structure. Seven different forms of iron sulfide scale have been identified. Only two of these iron sulfide forms are readily soluble in hydrochloric acid (HCl). The remaining iron sulfide scales are either slowly soluble or not significantly soluble.

- Chloride scales

Chloride scales, such as sodium chloride precipitation from water caused by temperature decrease or evaporation of the water, are common. There is no effective way to prevent salt precipitation, and cleanup has been accomplished using water only. Salt has a limited solubility in acid ( $\frac{1}{4}$  lbm/gal in 28% HCl), so using acid is not generally considered. Redesigning the mechanical system to avoid temperature loss and water evaporation is also a possibility.

- Silica scales

Silica scales generally occur as finely crystallized deposits of chalcedony or as amorphous opal. They are associated with alkaline or steamflood projects and stem from the dissolution of siliceous formation minerals by high-pH fluids (Lieu *et al.*, 1985) or high-temperature steam condensates (Reed, 1980; McCorriston *et al.*, 1981; Amaefule *et al.*, 1984). This dissolution can cause poorly consolidated sandstones to collapse or silica to reprecipitate at a distance from the wellbore where the alkalinity, temperature or both of the floods has decreased.

### 14-3.4. Organic deposits

Organic deposits are heavy hydrocarbons (paraffins or asphaltenes) that precipitate as the pressure or temperature is reduced. This is a form of distillation. They are typically located in the tubing, perforations or formation (Fig. 14-1). Although the formation mechanisms of organic deposits are numerous and complex (Houchin and Hudson, 1986), the main mechanism is a change in temperature or pressure in the flowing system. Cooling of the wellbore or the injection of cold treating fluids has a much more pronounced effect.

Organic deposits must not be confused with another type of deposit called sludge. Sludges are viscous emulsions produced by the reactions between certain crude oils and strong inorganic acids or some brines. Sludges cannot be easily dissolved.

- Paraffins

Paraffins are the simplest of hydrocarbons. They are composed of only carbon and hydrogen atoms, and the carbons occur as an unbranched chain. Carbon chain length associated with formation of solid paraffin deposits has a minimum of 16 carbon atoms per molecule and may have up to 60 or more. The precipitation of paraffins is triggered by a loss of pressure, loss of temperature or loss of short-chain hydrocarbon compounds (i.e., the light ends). The temperature at which the first solid paraffin crystal forms from an all-liquid solution is called the cloud point. Designing the completion so that produced fluid surface temperatures are above the cloud point and modifying the cloud point using chemical methods are accepted practices to prevent paraffin deposition in the tubing.

Melting points increase as the length of the paraffin chain increases. The hardness of the solid paraffin structure also increases with molecular size. Table 14-2 lists several paraffin chain lengths and their melting points. Impurities may cause the melting point of a field sample to vary slightly.

Paraffins can form anywhere in the producing system when conditions become favorable for precipitation (Cole and Jessen, 1960; Burger *et al.*, 1981; Newberry *et al.*, 1986; Thomas, 1988; Newberry, 1981; Sutton and Roberts, 1974). Paraffins are normally found in the tubing near the surface, where the temperature and pressure drops are highest. In cases such as reservoirs that are

**Table 14-2. Melting points of paraffins.**

Carbon Atoms (no.)	Melting Point (°F)
16	64
17	72
18	82
20	100
23	122
25	129
32	158
42	181
49	196
60	211

nearly pressure depleted or formations that have experienced dry gas cycling (which removes the light hydrocarbon ends), the paraffins can form at the perforations or in the formation. Paraffins may also be precipitated by the injection of a cool fluid. Although not typically considered, this latter cause can be the reason for the slow cleanup of many wells after stimulation.

- **Asphaltenes**

Asphaltenes are organic materials consisting of condensed aromatic and naphthenic ring compounds with molecular weights of several hundred to several thousand (Leontaritis, 1989; Leontaritis and Mansoori, 1987; Tuttle, 1983; Newberry and Barker, 1985; Addison, 1989; Bunker, 1979; Thawer *et al.*, 1990). They are characterized by the nitrogen, sulfur and oxygen molecules they contain and are defined as the organic part of the oil that is not soluble in a straight-chain solvent such as pentane or heptane. Asphaltenes are generally found in one of three distinctive forms:

- hard coal-like substance
- blackened sludge or rigid-film emulsion (usually triggered by iron in solution)
- in combination with paraffins.

In “solution,” they usually exist as a colloidal suspension, forming particles 30 to 65 Å in diameter and stabilized by maltene molecules in the oil. The volume of the maltene resins is the first key to the stability of the asphaltene in suspension. The actual quantity of asphaltenes in the oil is much less important. The stability of asphaltic dispersions depends on the ratio of the quantity of resins

to the quantity of asphaltic materials. Ratios larger than 1:1 (resins to asphaltenes) are more stable, whereas ratios less than 1:1 are unstable and may precipitate during production. Ratios of more than 10:1 are known and are much less likely to cause significant problems. Although asphaltene contents up to 60% have been found, major problems occur with oils with a 1% to 3% asphaltene range.

Asphaltene precipitation can be influenced by pressure drop, shear (turbulence), acids, solution CO<sub>2</sub> (lowers the pH value), outgassing of CO<sub>2</sub> and other gases (turbulence), injected condensate, gas, commingling with other (incompatible) oils and charged metal surfaces (Danesh *et al.*, 1988; Monger and Trujillo, 1991; Kawanaka *et al.*, 1991; Monger and Fu, 1987; Pittaway *et al.*, 1987). Anything that takes away the resins or breaks the stability of the aggregate particle can lead to a precipitation of asphaltene. Iron ions in solution (usually during an acid job) compound and favor the formation of asphaltene deposition. As noted previously, the concentration of asphaltenes is not a good indicator of potential problems. Only the treatment history and well response examination can suggest the potential for asphaltene problems.

Asphaltene deposition on pore walls may not significantly decrease the formation porosity and absolute permeability. However, through this process, the rock tends to become oil-wet, which reduces the relative permeability to oil (Clementz, 1982; Collins and Melrose, 1983) and, under certain conditions, favors the buildup of emulsion blocks if water is simultaneously produced.

- **Tar**

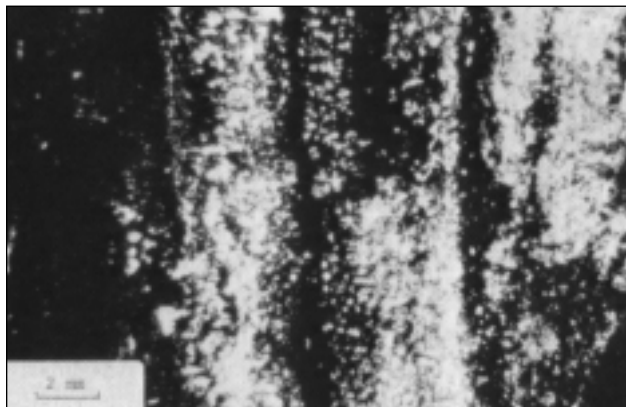
Tar is simply an asphaltene or other heavy-oil deposit. It cannot be removed by acid or mutual solvents. Removal requires dispersion in an aromatic solvent, and energy is typically necessary to achieve removal.

### 14-3.5. Mixed deposits

Mixed organic/inorganic deposits are a blend of organic compounds and either scales or fines and clays. When migrating, fines associated with an increase in water production in a sandstone reservoir become oil-wet, and they act as a nucleation site for organic deposits (Houchin and Hudson, 1986).



Figure 14-5 shows such a mixed deposit in which clear (white) crystals of sodium chloride are dispersed in a dark organic matrix.



**Figure 14-5.** Thin section of a layered matrix deposit. The black layers are organic deposits, and the clear (white) layers are inorganic scales of mainly halite (NaCl).

### 14-3.6. Emulsions

Emulsions are combinations of two or more immiscible fluids (including gas) that will not disperse molecularly into each other (Hoover, 1970; Sherman, 1968; Lissant, 1974; Lissant and Mayhan, 1973; Bandbach, 1970; Hausler, 1978; Bikerman, 1964; Ogino and Onishi, 1981; Gidley and Hanson, 1973; Coppel, 1975). Emulsions are composed of an external phase (also called nondispersed or continuous) and an internal phase (also called dispersed or discontinuous). The internal phase consists of droplets suspended in the external phase. Almost all emulsions found in the field are produced by the addition of some form of energy that produces mixing. Most emulsions break rapidly when the source of energy is removed. The breaking mechanism of these unstable emulsions is by droplet contact and growth and then by fluid density separation. As the droplets draw near and touch, the surface film around the drop may thin and rupture, forming large drops in a process called coalescence. The larger droplets settle rapidly owing to density differences between the liquids forming separate layers. Only a portion of the drops that touch will coalesce. When minimum coalescence occurs, the emulsion is stable.

If separation of the emulsion does not occur, there is a stabilizing force acting to keep the fluids emulsified. The most common stabilizing forces are a modi-

fication of the surface film strength at the interface by chemical reaction, precipitation or the addition of partially wetted fine particles, electric charge, or high viscosity of the components or resultant fluid viscosity. These forces may act singly or in combination.

Natural surfactants help stabilize emulsions by stiffening the film around the droplet or by partially wetting small solid particles. Natural surfactants are present in many waters and most crude oils. They may be of several chemical formulas and may be a by-product of bacteria or originate as part of the oil-generation process. Like other surfactants, they have an oil-soluble end and a water-soluble end (usually possessing a small electric charge) and congregate at the oil/water interface.

Micron-size solids in the liquid may stabilize an emulsion by increasing the toughness of the surface film around the droplets or by acting as an emulsifier and binding droplets of the dispersed liquid with an electrical charge. Almost any solid can be a stabilizing agent if it is sufficiently small. For a solid to be effective in stabilizing an emulsion, it must be present at the interface of the drop and the continuous phase. The more common solid materials that stabilize oilfield emulsions are iron sulfide, paraffin, sand, silt, clay, asphalt, scale, metal flakes (from pipe dope), cuttings and corrosion products.

Changes in the pH value can affect emulsion stability. Most free-water knockouts and treaters operate efficiently at a pH value of 6 to 7, depending on individual well conditions. Following an acid treatment, the pH value may drop below 4 and emulsions may be created. Emulsions created in this manner are stable until the pH value rises above 6 or 7. When acid treating a well where the crude is an emulsifier or a sludge former, the wellhead may be equipped with a chemical injection port just upstream of the choke or a chemical injection valve may be placed in a gas-lift mandrel at some point in the treatment string. These ports are used to inject an emulsion breaker or de-emulsifier.

### 14-3.7. Induced particle plugging

In addition to naturally occurring migrating particles such as clays and fines, many foreign particles are introduced into the formation during normal well operations. Drilling, completion, workover, stimulation, and secondary or tertiary production operations

can cause the injection of extraneous particles into the formation.

Particle damage from injected fluids happens in the near-wellbore area, plugging formation pore throats. Problems include bridging of the pores, packing of perforations and the loss of large amounts of high-solids fluid into natural fractures or propped fracture systems. The best method of avoiding this type of damage is to use a clean fluid in a clean flow system with a controlled range of particle sizes that will stop fluid loss quickly by bridging at the wellbore.

Induced particles can be composed of a wide range of materials. Particulate materials in drilling fluids that are potentially damaging are clays, cuttings, weighting agents and loss-control materials, including polymers (Barna and Patton, 1972; Fisher *et al.*, 1973; Sloan *et al.*, 1975). These materials can be a problem independent of mud type (oil, water or polymer base). Workover and stimulation fluids can also contain suspended solids (Rike, 1980; Rike and Pledger, 1981) including bacteria and polymer residues (Tuttle and Barkman, 1974). Kill fluids in particular use various polymers as weighting agents or for fluid-loss control. Typical kill-fluid solids include salt pills with polymer, crosslinked polymers, hydroxyethylcellulose (HEC) polymers, lost-circulation pills and  $\text{CaCO}_3$  with polymer.

Particles in stimulation fluids are a result of poor water quality, tank coatings, tank residuals, and piping and tubing debris (e.g., dried mud, scale and pipe dope). The problem with stimulation fluids is that they can contain effective cleaners and acids that disperse and partially dissolve the debris inside of the tanks and piping on their way to the formation.

Particle damage after stimulation may also occur when partially dissolved parts of the formation or the damage materials come back, through either the pores or the natural fracture or propped fracture system. The release of fines from the formation is usually brought about by cleaners and mutual solvents. Acid treatments may also cause formation damage because of the precipitation of secondary acid reaction products. Precipitation products include iron hydroxide, calcium fluoride, potassium fluorsilicate and silica.

Geochemical models can predict the chemical nature of these by-products, depending on formation rock and treatment fluid compositions on one hand and pressure, temperature and contact time on the other (Walsh *et al.*, 1982; Dria *et al.*, 1988). The

models cannot predict the damaging potential of these products because they do not include any physical description of the way they are precipitated. Hydrated silica (Crowe, 1985) may precipitate on clay surfaces but is not necessarily damaging. Compounds such as borosilicates (Thomas and Crowe, 1978) and fluoborates (Bertaux, 1989) can even be beneficial, probably because they precipitate as films that bind fines to the sand grains. This phenomenon, when purposely produced, leads to efficient fines-stabilization treatments (Thomas and Crowe, 1978; Sharma and Sharma, 1994). However, gelatinous precipitates, such as ferric hydroxide, can completely plug pores and can be particularly difficult to remove (Crowe, 1985). Another class of by-products consists of species such as fluorsilicates (Bertaux, 1989), which precipitate in the form of individual crystals that can migrate toward pore throats and produce a "log jam." Iron sulfide, which precipitates even at low pH values during the acid treatment of sour wells, is another compound belonging to this category.

### 14-3.8. Wettability alteration

Formation plugging can be caused by liquid (or gas) changing the relative permeability of the formation rock. Relative permeability can reduce the effective permeability of a formation to a particular fluid by as much as 80% to 90%. The wettability and related relative permeability of a formation are determined by the flowing-phase quantity and by coatings of natural and injected surfactants and oils.

If a drop of a liquid is placed on the surface of another immiscible liquid or on the surface of a solid that it cannot dissolve, it may spread out into a thin film or it may remain in the form of a drop or a thick lens (Hausler, 1978). If the drop of liquid spreads, it wets the surface; if the drop of liquid does not spread, it does not wet the surface. The surface free energy of the two phases and the interfacial tension between them determine whether the liquid spreads or remains in a deformed drop. Wettability is measured by the contact angle that a droplet of fluid forms on a particular surface. If the angle of contact  $\theta$  is less than  $90^\circ$ , the drop spreads from the initial ball shape and the surface is said to be wetted by the liquid. The smaller the angle, the greater the water wettability. If the angle is more than  $90^\circ$ , the surface is not wetted by the liquid. Wettability can be mea-

sured with a liquid surrounded by gas or a liquid surrounded by an immiscible liquid. Simple wetting has little meaning—it is the resultant effect of wetting on fluid flow that is important.

In the natural state, formations may be water-wet, oil-wet or neutral, depending both on the surface exposed to the fluid and the natural surfactants in the fluid. There are some instances, such as the Cardium reservoir in Alberta, Canada, where both oil- and water-wetting behavior have been reported in different sections of the reservoir.

When a surface of a pore passage is oil-wet, more of the passage is occupied by the bound oil (thicker monomolecular layer), and less of the pore is open to flow than in a water-wet pore. Naturally, to get as much flow capacity as possible in a formation, it is desirable to change the wettability to water-wet (in most cases). Unfortunately, it is impossible to change most naturally oil-wet surfaces for long. Wettability can be modified by preflushing the formation with a wetting surfactant or a solvent that establishes a new coating on the face of the formation or cleans the current coating from the formation. Regardless of the altered condition of a surface, the wettability is eventually decided by the surfactants in the produced fluid. Thus, the water-wet condition of a formation following an acid job can revert to an oil-wet condition after a sufficient volume of strongly oil-wetting crude is produced.

#### 14-3.9. Acid reactions and acid reaction by-products

Numerous problems that may occur during acidizing treatments include

- damaging material from the tubing entering the formation
- oil-wetting of the reservoir by surfactants, especially corrosion inhibitors, which can create emulsion blocks
- water blocks
- asphaltene or paraffin deposition when large volumes of acid are injected.

In addition to these common damaging processes, production impairment can result from poor design of an acidizing treatment. Impairments include the following:

- sludges produced by the reaction between acids and asphaltenes, especially in the presence of some additives (particularly surfactants) or dissolved iron
- by-products precipitated by the reaction of acids with formation materials. Geochemical simulators can predict the chemical nature of the by-products, depending on the formation rock and treatment fluid compositions and the pressure and temperature. Simulators cannot predict the damaging potential of the by-products. Hydrated silica may precipitate on clay surfaces and is not necessarily damaging. Compounds such as borosilicates and fluoborates can even be beneficial. Gelatinous precipitates, such as ferric oxide, can completely plug pores and be particularly difficult to remove. Another class of by-products consists of species such as fluorsilicates precipitating in the form of individual crystals that can migrate toward pore throats and then bridge in the throats. Iron sulfide that precipitates, even at very low pH values during the acidization of sour wells, is another compound belonging to this category.
- precipitates formed by the addition of certain sequestering agents to acids to prevent iron problems when the acid is spent and no iron is present
- permeability impairment by residues present in corrosion inhibitors or produced through the thermal degradation of polymers, such as friction reducers.

#### 14-3.10. Bacteria

Although many microorganisms can be present in the unsterile world of the oilfield, only a handful produce widespread problems (Shuler et al., 1995; Clementz *et al.*, 1982; Crowe, 1968; Carlson *et al.*, 1961; Raleigh and Flock, 1965). Bacteria can be a serious problem in production operations because of what they consume and their by-products. Bacteria can grow in many different environments and conditions: temperatures ranging from 12°F to greater than 250°F [–11° to >120°C], pH values ranging from 1 to 11, salinities to 30% and pressures to 25,000 psi.

Bacteria are classified as follows:

- Aerobic bacteria are bacteria that require oxygen.

- Anaerobic bacteria do not need oxygen (in fact, their growth is inhibited by oxygen).
- Facultative bacteria can grow either with or without oxygen because their metabolism changes to suit the environment. They usually grow about 5 times faster in the presence of oxygen.

The bacteria most troublesome in the oilfield are sulfate-reducing bacteria, slime formers, iron-oxidizing bacteria and bacteria that attack polymers in fracturing fluids and secondary recovery fluids.

Sulfate-reducing bacteria cause the most problems in a reservoir. Sulfate-reducing bacteria reduce the sulfate or sulfite in the water to sulfide and produce hydrogen sulfide ( $H_2S$ ) as a by-product. The reduction process provides the energy for bacterial growth. Biomass accumulation can lead to pitting of the steel under large colonies. The  $H_2S$  increases the corrosivity of the water and creates the possibility of blistering of carbon steels and sulfide cracking. The by-product of an  $H_2S$  attack on steel is iron sulfide (the general form is  $FeS$ ). Sulfate-reducing bacteria are anaerobic bacteria with slow growth rates when oxygen is present. Sulfate-reducing bacteria occur naturally in surface waters, including seawater. The growth of the sulfate-reducing bacteria is controlled by temperature and limiting their access to nutrients. The primary nutrients are carbon, nitrogen, phosphorus and dissolved iron. Bactericides are also used commonly to control these bacteria.

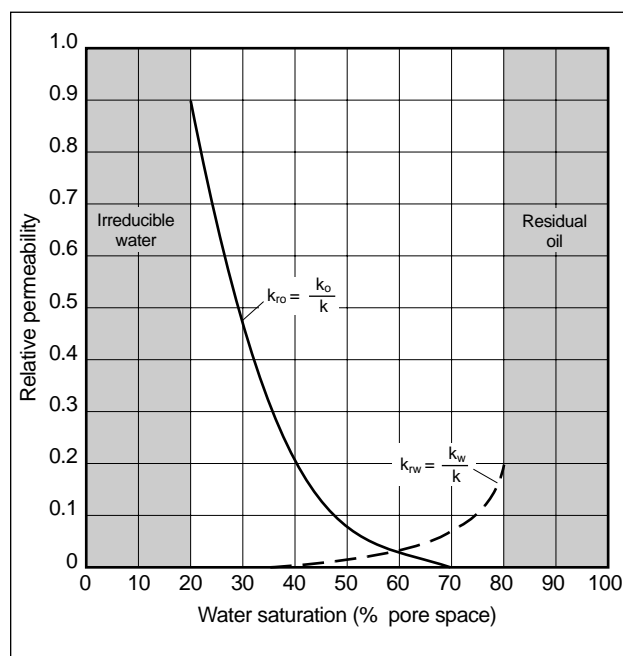
Iron-oxidizing bacteria are aerobic and convert iron from the ferrous ( $Fe^{2+}$ ) to the ferric ( $Fe^{3+}$ ) state. They produce gelatinous ferric hydroxide, which is highly insoluble and precipitates out of water. The bacteria metabolize dissolved iron in the water. Ferrous iron is soluble only at low pH values (i.e., when the water is acidic). Therefore,  $FeOH_3$  is typically considered an acid-reaction product. The iron-oxidizing bacteria produce some corrosion, but they usually cover sulfate-reducing bacteria colonies and protect them from attack.

Slime-forming bacteria are facultative and produce mats of high-density slime that cover surfaces. Their primary detrimental effects are the protection of colonies of sulfate-reducing bacteria and pore plugging.

The bacteria that attack polymers are various aerobic types and a few of the anaerobic bacteria. Most polymers are excellent carbon sources that are readily consumed to support rapid bacterial growth rates. The resulting large quantities of biomass contribute to formation plugging. All these bacteria can be controlled by the application of various biocides.

### 14-3.11. Water blocks

Water can cause blocking in low-permeability rocks (Fig. 14-6) (Keelan and Koepf, 1977). Water blocks are a special case of relative permeability problems. In a water block, water usually occupies the flowing spaces (either pores or natural fractures) that are typically used by hydrocarbons to flow to the wellbore. Because of the mobility and viscosity differences, the hydrocarbon fluid may not be capable of displacing the water. The most severe cases of water blocks are usually observed in low-pressure, low-permeability, gas-producing formations after treatment with water that has a high surface tension.



**Figure 14-6.** Water blocks: increasing the water saturation from 20% to 35% decreases the relative oil permeability from 90% to 30%, respectively (Keelan and Koepf, 1977).  $k_o$  = oil effective permeability,  $k_{ro}$  = oil relative permeability,  $k_w$  = water effective permeability,  $k_{rw}$  = water relative permeability.

### 14-3.12. Oil-base drilling fluids

Oil-base mud (OBM) is the drilling fluid of choice for the lubricity required in many highly deviated wells and for formations that are extremely sensitive to water-base mud (WBM). Most OBMs, and particularly those with densities greater than 14 lbm/gal, contain sufficient solids to create silt-stabilized emulsions when mixed with high-salinity brines or acids. These emulsions are viscous and resist breaking. Some of these emulsions have been shown to be stable for several months, both in the laboratory and in the wellbore. The level of damage caused by these emulsions can be so severe that an entire pay zone can be missed. For example, in a South Texas well the OBM emulsion created damage so severe that almost no flow from the well could be measured. When the damage was removed, the well tested at more than 12 MMscf/D.

A related problem with OBM is the relative permeability effects commonly created by the powerful wetting surfactants used for creating stable OBM. When these materials coat or adsorb onto the formation, the wettability of the formation is altered, and permeabilities may be only 10% to 20% of what they were initially. The most severe problems usually occur with muds weighing more than 14 lbm/gal. The main cause of problems is oil-wetting of the fines from weighting and viscosifying agents and from cuttings.

## 14-4. Origins of formation damage

This section describes the origins of formation damage and reviews typical well operations, including drilling, cementing, completion, gravel packing, production, stimulation and injection for enhanced oil recovery. All are potential sources of damage. Damage is also commonly categorized by its associated well operation (Tables 14-3, 14-4 and 14-5).

### 14-4.1. Drilling

- Mud solids invasion

Mud solids can progressively fill the porosity of the reservoir rock if forced into the pay zone. Subsequent attempts to start production or injection at moderate or high flow rates may cause

these materials to bridge and severely decrease the permeability of the near-wellbore area.

Such damaging processes are usually limited to the first few inches around the wellbore (an average value of 3 in. is commonly used), but the resultant permeability reduction can be as high as 90%. Invasion of formation rock by drilling fluid solids is favored by

- large pore size of the formation rock (Brownson *et al.*, 1980)
- presence of fissures and natural fractures in the reservoir
- small particle size of the solid components of the drilling fluid (the initial particle size of weighting agents and lost-circulation preventers is usually coarse but can be fragmented by the drill bit) (Abrams, 1977)
- low drilling rate resulting in mudcake destruction (mud-loss increase) and long formation-to-mud contact time
- high drilling fluid circulation rate (mudcake erosion)
- high drilling fluid density causing large overbalance pressure (Givens, 1976)
- scraping of mudcake, provoking pressure surges and increasing formation-to-mud contact time during bit trips (Records, 1976).

Using clear brines (containing no particulate materials) as drilling fluids minimizes formation invasion by fines but may create a large loss of fluids in the rock matrix.

When drilling a formation with natural fractures, some mud loss is expected in the natural fracture system. Because natural fractures are important to reservoir flow, avoiding loss of mud to the fracture system by using a high-quality fluid-loss control system is crucial. If the natural fractures are already damaged by mud, the success of the cleanout will depend on how much mud was lost and the type and condition of the mud when it was lost. If a low-solids mud was used in a system with minimal overbalance, little damage may have occurred. If a high-weight mud system with a large amount of fines was used or if the drilling overbalance was high (more than 2 lbm/gal overbalance equivalent), damage may be severe.

**Table 14-3. Initial damage during drilling or completion.**

Condition or Type of Damage	Diagnostic Clues	Remedial Operation
Unstable formation	<p>May occur in any formation that is poorly consolidated or that will fail under pressure</p> <p>May occur with onset of water production or loss of pressure from depletion</p> <p>Problems include embedment of proppant, closing of acidized channels in acid fractures, spalling of formation into perforations or wellbore, or production of solids.</p>	Gravel packing, fracture packing, plastic consolidation or production rate limits
Oil-base mud emulsion damage	<p>Common in wells drilled with OBM</p> <p>If treated with acid or brine before the sulfonate emulsifiers are washed off the cuttings by production or solvent treatments, an emulsion can lock up the well.</p> <p>The first one or two treatments may be short-lived as more mud and mud filtrate move back toward the wellbore, as is often the case in naturally fractured formations.</p>	<p>Wash with aromatic solvent followed by mutual solvent and acid</p> <p>May require several treatments</p> <p>Cuttings removal is important.</p>
Fracture plugging from mud	<p>Large whole-mud losses in naturally fractured formations</p> <p>Intermittent production at low and moderate rates</p> <p>Infrequent recovery of whole mud and mud fines</p> <p>Some emulsions, especially after acid treatments</p> <p>May also occur if the hole is poorly cleaned during drilling</p>	<p>Acid useful if damage is shallow</p> <p>Fracture if damage is deep</p> <p>Prevent by improving solids recovery</p> <p>In severe cases, a sidetrack drill of the pay may be necessary.</p>
Particle damage from drilling and completions	<p>Skin effect on buildup test</p> <p>Injection difficult</p> <p>May show emulsions in oil wells</p> <p>Poor mud conditioning before cement</p> <p>Common in openhole completions and horizontal wells</p>	<p>HCl or HCl-HF in matrix acid job and solvent wash followed with acid in wells with OBM</p> <p>Foam or jetting cleanups can be useful.</p>
Poor perforations	<p>Shows up as damage on a buildup test but cannot be cured with acid or mechanical changes in the well</p> <p>Common problems are screenouts of fracture downhole scale occurrence, unstable emulsions, and downhole paraffin and asphaltene deposits.</p>	<p>Reperforate</p> <p>Problems with a well that cannot be broken down or even pumped into should always be approached by reperforating the well.</p>
Cement in natural fractures	Poor well response following completion when possible perforation problems have been eliminated	Small fracture treatment or sidetrack drill

**Table 14-4. Damage during and after stimulation.**

Condition or Type of Damage	Diagnostic Clues	Remedial Operation
Migrating fines	<p>Kaolinite or fibrous illite clay or some feldspars (nonclays)</p> <p>Brine changes may trigger fines movement.</p> <p>Sporadic reductions in flow rate</p> <p>Variable production rate tests</p> <p>Fines in produced fluids</p> <p>Emulsions rare but possible</p>	<p>Clay control for prevention</p> <p>Retarded acid for removal</p> <p>May require limiting rate in extreme case or fracture treatment to spread out draindown</p>
Particle damage after stimulation	<p>May also occur following acid or fracture stimulations or workover fluids where dirty water was used or the water was hauled or stored in a dirty tank</p>	<p>Filter treatment fluids</p> <p>Use clean tanks</p>
Particles in waterfloods	<p>Reduced injection rate</p> <p>Higher injection pressures</p> <p>Backflow shows particles and oil carryover return.</p>	<p>Better water filtering</p>
Wettability problems	<p>Commonly occurs after an acid job where the corrosion inhibitor was not mixed in the acid just before injection</p> <p>Emulsions and reduced flow are common, particularly after inhibitor loss or OBM contact. May be permanent, but usually cleans up slowly with time and flow</p> <p>Attempts to reverse natural wettability are usually short-lived.</p> <p>Natural wettability is determined by the natural surfactants in the produced fields.</p>	<p>Treat with mutual solvent wash over the pay, displace and soak</p>
Relative permeability problems	<p>May occur when oil is injected into a gas zone or gas is injected into an oil zone that is above the bubblepoint</p>	<p>Treat with a high-API-gravity solvent such as condensate or xylene (low flash point)</p> <p>Squeeze and produce back</p>
Poor load-fluid recovery	<p>Usually formation dependent</p> <p>May decrease production rate in severe cases or cause a long cleanup time</p> <p>Most common in formations with small pores and in microporous clays</p>	<p>Avoid or minimize water contact and lower the surface tension of the water to prevent</p> <p>Removal with alcohols and some surfactants</p>
Water blocks	<p>Usually in gas wells with small pore throats, untreated water and low-pressure formation</p> <p>If low pressure (less than about 0.2 psi/ft), the pore throat size has no effect</p>	<p>Matrix treat with alcohol or surface-tension-lowering surfactant</p> <p>Inject gas in gas reservoir to a distance of 10 ft</p>
Swelling clay	<p>Smectite clay, some illite and smectite interbedded clay</p> <p>Permeability is sensitive to change in water salinity or brine type.</p>	<p>Acidize with HCl-HF if damage is shallow</p> <p>Fracture if damage is deeper than 12 in.</p>
Microporosity (water trapping)	<p>Caused by some forms of clay</p> <p>May bind water and make high <math>S_w</math> readings on log without water production</p>	<p>No treatment necessary</p>

**Table 14-5. Damage during production.**

Condition or Type of Damage	Diagnostic Clues	Remedial Operation
Retrograde condensate	<p>This special case of the relative permeability effect is a condensate (liquid phase) that forms from a rich gas.</p> <p>If the condensate forms in the tubing or casing, heading may occur.</p> <p>If the condensate forms in the formation, creation of another phase will reduce permeability to gas.</p> <p>Usually occurs near the wellbore as pressure drops there</p>	<p>Control drawdowns and repressure reservoir</p> <p>Redesign tubing if forming in tubulars</p>
Paraffins in tubulars	<p>Pressure restriction in tubulars</p> <p>Soft to hard mass found at pressure drops</p> <p>Reddish brown to black in color, with white or gray also possible</p> <p>Also commonly occurs in tubing near the surface as oil cools and the cloud point is reached</p> <p>May increase as a problem as a field ages</p> <p>Most paraffin deposits melt at less than 150°F [65°C].</p>	<p>Scraping and cutting for mechanical removal</p> <p>Hot oil useful if the deposit is less than 100 ft from surface</p> <p>Solvent soaks on deeper deposits</p> <p>Inhibitors available for pipelines and some problem wells</p> <p>Some wells require continuous downhole treatment through "macaroni string."</p> <p>Special bacteria are useful.</p>
Paraffins in flowlines	<p>Soft to hard deposits (not a scale) in surface flowlines and equipment</p> <p>Paraffin melts when exposed to sufficient heat . (usually about 150°F).</p>	<p>Mechanical or solvent removal or pigging</p> <p>Inhibitors can be used</p>
Paraffins after stimulation	<p>Injection of a cool stimulation fluid may precipitate paraffin in the reservoir on contact.</p> <p>The well may be cleaned up slowly (1 to 4 weeks) after stimulation, although load fluid is recovered faster.</p> <p>May have decreasing skin if multiple buildup tests are performed</p>	<p>Allow the well to clean up on its own</p> <p>Where this problem is known to occur, prevent by using xylene preflush ahead of acid</p>
Paraffins in formation	<p>Seen as skin on test</p> <p>May disappear if well is shut in for several days</p> <p>Cloud point of oil is near the reservoir temperature.</p> <p>Pressure drop may trigger paraffin drop out.</p>	<p>Treat with downhole heat-generating processes if the well is a good producer</p> <p>Solvent soaks also used</p> <p>Some inhibitors can be used with a fracture treatment.</p>
Asphaltenes	<p>Black, soft to hard mass that may occur as flakes, sludge, marble-size balls and a sticky buildup that occurs with paraffins</p> <p>Precipitation is triggered by destabilization of maltene resins caused by acid contact, outgassing, shear in pumps, electrically charged metal surfaces, temperature reduction and CO<sub>2</sub>.</p> <p>Asphaltenes soften with increasing temperature (&gt;150°F) but do not melt.</p>	<p>Treatment with aromatic (cyclic ring) solvents such as xylene or toluene</p> <p>Some surfactants are also useful for dispersion of the asphaltic mass.</p> <p>Use antisludge additive or xylene with acid in reservoirs with more than 0.5% asphalt to prevent sludges</p>



**Table 14-5. Damage during production (continued).**

Condition or Type of Damage	Diagnostic Clues	Remedial Operation
Tar	<p>Flows slowly into perforations during production of oil</p> <p>Usually associated with the presence of a tar deposit near pay and typically highly asphaltic</p> <p>May contain some water that is tied up as droplets or "pockets" in the high-viscosity mass</p>	<p>Solvent soak as required</p> <p>Test solvent with sample of tar before job</p> <p>Heat often helps.</p>
Emulsion	<p>Unstable emulsions that break on standing</p> <p>Created in tubing at pressure drop points in the piping system from pumps to choke</p>	<p>No downhole treatment suggested</p> <p>Treat on surface if string redesign is impractical</p>
Silt-stabilized emulsion	<p>Stable emulsion with partially wetted fines at interface</p> <p>Common after drilling mud dispersal or cleanup of mud or cement fines by acid</p> <p>May also occur on polymer cleanup</p> <p>Common in production from unconsolidated formations, especially after acid or gravel-pack operations</p>	<p>Treat with mutual solvent and acid</p> <p>Remove downhole source of solids if possible</p>
Surfactant-stabilized emulsion	<p>Stable to highly stable emulsion</p> <p>Common to severe after acid treatment</p> <p>Stabilized skin may be seen at the drop interface.</p>	<p>Treat on surface if temporary</p> <p>Use mutual solvent or surfactant to prevent emulsion with next acid treatment</p>
Sludge (iron/asphaltic)	<p>Sludge is an emulsion that is nearly solid.</p> <p>May be triggered by acid, OBM, asphaltenes or iron compounds</p> <p>Disperse the sludge in xylene and analyze for components, particularly iron</p>	<p>Prevention is the best cure.</p> <p>Use nonsludging acid systems, and test at the iron content expected in the well</p>
Bacterial infestation	<p>This difficult problem to predict is more common in injection wells where surface or produced water is injected.</p> <p>If the colony is established in the water handling system, it can occur with the injection of any waters.</p> <p>Brown to black slimy masses or an H<sub>2</sub>S odor when tubing is pulled</p> <p>Bacteria may cause slow reductions in the injectivity of an entire field.</p> <p>Complete removal of bacteria is rarely possible.</p> <p>Treatment is usually on a remedial basis.</p> <p>Untreated water in treatments</p> <p>Drilling fluid or injection water can sour reservoirs with sulfate-reducing bacteria.</p>	<p>Treat with sodium hypochlorite followed by HCl (do not allow contact of sodium hypochlorite and HCl)</p> <p>More than one treatment may be necessary.</p> <p>Alternative treatments are chlorine dioxide and bactericide slugs.</p>
Calcium carbonate scale	<p>May form at any pressure drop, either in the formation or tubulars</p>	<p>HCl to remove and inhibitor to prevent</p>

**Table 14-5. Damage during production (continued).**

Condition or Type of Damage	Diagnostic Clues	Remedial Operation
Calcium carbonate scale (continued)	<p>May form quickly and can sharply limit production, especially at gravel-pack interfaces or near perforations in wells with high drawdown across the perforations</p> <p>May be more common in earlier stages in some fields when the pressure drop is more severe</p> <p>Usually has no crystal pattern</p>	<p>Inhibitor may be squeezed into the formation for longer lived protection.</p> <p>Some HCl jobs may trigger calcium carbonate scale in rare cases; inhibit acid or treat with EDTA if this is a problem.</p>
Calcium sulfate scale	<p>Usually forms at pressure drop induced by turbulence or dissolver with acid)</p> <p>More common where high-sulfate waters contact high-calcium waters and in CO<sub>2</sub> floods</p> <p>Scale is not acid soluble.</p> <p>May be found on the outside of pumps and at intakes and gas expulsion ports and valves downhole</p> <p>Crystals are characteristic for this scale.</p>	<p>Chemical converter or dissolver followed by acid (do not contact converter</p> <p>Acid is not useful alone.</p> <p>Inhibitors placed by squeeze treatments are useful for prevention.</p>
Barium sulfate scale	<p>Nonreactive scale that forms at pressure draw-downs or where outgassing occurs</p> <p>No readily apparent crystal pattern in many deposits</p> <p>May occur as NORM scale in areas where radioactive isotopes form in the lattice</p> <p>NORM scales are detectable with gamma ray logging tools.</p>	<p>Scraping, water blasting or other mechanical removal</p> <p>Chemical treatment is usually not possible if scale occurs as a nearly pure (greater than 90%) deposit or as thick (greater than ¼ in.) deposits in pipe.</p> <p>Can be prevented by inhibitors</p>
Iron carbonate scale	<p>Carbonate scale tendencies with large iron content</p> <p>Molar acid reactivity on the scale</p> <p>Brownish colored scale (cleaned of oil)</p>	<p>HCl for thin deposits or mechanical removal where possible</p>
Iron sulfide scale	<p>Hard scale, dense and heavy</p> <p>Many forms are not acid soluble.</p> <p>Some forms are mildly magnetic.</p>	<p>Mechanical removal with mills or cutters</p> <p>Water jets may not work.</p>
Salt	<p>Precipitates as a white mass in the tubulars or in the formation</p> <p>Usually associated with a cooling of super-saturated water, but can also be triggered by a pressure drop</p> <p>May be seen early in some wells but becomes less of a problem as the water cut increases</p> <p>Problems in formations with produced water salinity that is near saturation</p>	<p>Freshwater or weak brine wash</p>
Hydrates (ice) in gas wells	<p>Gas well with intermittent flow to nearly total shutoff, followed by return to flow in a few minutes</p> <p>Produces a small amount of water</p>	<p>Glycol or alcohol injection below the hydrate formation point</p> <p>Insulated risers or tubing</p>

**Table 14-5. Damage during production (continued).**

Condition or Type of Damage	Diagnostic Clues	Remedial Operation
Hydrates (ice) in oil wells	In oil wells, usually forms only near the mudline in Arctic regions  May also form in drilling fluid	Insulated risers
Fill in perforations	High skin effect  Well can be injected into at low rates.  Reperforating may show sharp increases.	Clean out or reperforate
Fill in casing	High skin effect  Difficult or impossible to inject into well  Partial fill shows skin effect on a buildup test, but injection is possible at a reduced rate.  Confirm with a sinker bar on wireline	Reverse circulation or regular circulation
Water coning	Onset of water production after extended production  Formation has no vertical permeability barriers and sufficient vertical permeability to allow water to move toward drawdown.	Limit rate  Some treatments may be temporarily useful.  Most water control products are not useful without natural reservoir barriers
Waterflood breakthrough through high-permeability zone	Examine produced water analysis and compare with flood water for identification  Watch for scale	High-permeability zones should be plugged deep (depth greater than 100 ft) from producer and injector when oil recovery from the zone is complete.
Commingled water production	Initial production of water with oil in primary, with breakthrough in flood  Water cut increases in flood.	Temporary or no treatment
Collapsed pipe	May show up as reduced rate or destruction of lift equipment  Check with a gauge ring on wireline or tubing  Most common causes are earth-shift loads caused by subsidence of producing formations with fluid and sand withdrawals, active faults and formation movement near salt zones.  Other causes include severe corrosion, malfunctioning perforating guns, pipe flaws and wear of tubulars from drilling or lift system.	If caused by earth-shift forces, use heavier pipe or multiple strings  Liners, cement and patches are used for repair.
Tubing problem	Well refuses to flow although pressure is sufficient with the expected assistance from dissolved gas.  Well may load up and die, or liquid slugs may be produced if the string is too large.  Rate is restricted by friction backpressure if tubing is too small.	Redesign string  A velocity string that fits inside the existing tubing may help if tubing is too large.
Leaks	Sudden changes in gas/oil ratio, water/oil ratio, pressure or chemical analysis of water	Repair  Consider corrosion control program

- Drilling fluid filtrate invasion

For economic reasons, wells have to be drilled as fast as possible. To increase the penetration rate, it is tempting to reduce the fluid-loss control of the mud (Black *et al.*, 1985; Simpson, 1985a, 1985b; Montgomery, 1985). About 600 bbl of fluid can be lost into a typical formation (Kutasov and Bizanti, 1985) during the drilling of a 10,000-ft well.

Higher values of filtrate invasion may result from the deliberate choice of high penetration rates. Before this decision is made, the effect of the filtrate and any associated solids should be known.

The liquid phase of a drilling fluid also contains many potentially damaging compounds. Because filtrate invasion can be deep, as shown in Table 14-6 (Simpson, 1974; Hassen, 1980), drilling filtrate damage can be one of the most important causes of production impairment. The severity of this damage depends on the sensitivity of the formation to the filtrate. High-permeability clean sandstones undergo more invasion than low-permeability reservoirs (Phelps *et al.*, 1984) but are more likely to be less affected when their connate water is chemically compatible with the filtrate. An average permeability reduction of 40% has been suggested; however, any value between 0% and 100% is possible, depending on the nature of the formation rock and fluids.

Sensitive formations contain clays that can be dispersed or swollen, are low-permeability rocks in which saturation problems dominate or are reservoirs producing almost saturated brines or high-content asphaltene or paraffin oils.

Problems with clays are not detailed here.

However, any change in the salinity of the pore fluids may affect the stability of clay particles in the porous medium. In particular, reducing the salinity or increasing the pH value of the water surrounding clay particles can promote dispersion of these materials. Destabilized formation fines act similarly to mud particles forced into formation rocks. As production or injection starts, fines migrate toward pore throats and either block them or bridge over them, depending on the particle size. The severity of the resulting permeability impairment varies with the fines concentration in the reservoir rock (Krueger *et al.*, 1967; Drodody *et al.*, 1988; Jiao and Sharma, 1992).

Factors that increase the probability of drilling fluid invasion include

- high permeability of the mud filter cake (a result of either poor design of the drilling fluid or detrimental drilling procedures)
- high overbalance
- long formation-to-drilling-fluid contact time.

WBM filtrates may have a low salinity and a high pH value and may contain dispersants and polymers. Water is a cause of in-situ clay disturbance and water blocking in low-permeability rocks (Keelan and Koepf, 1977). The numerous drawbacks of water-base drilling fluids led to the development of OBM for drilling through sandstones containing clay (Methven and Kemick, 1969). The initial conclusion was that this new mud was a safe, all-purpose drilling fluid. It is now recognized, however, that although the problems of OBM are less numerous than those of WBM, they are commonly much more severe (Goode *et al.*, 1984). OBM filtrates contain additives that cause emulsion and wettability problems (Ballard and Dawe, 1988; McKinney and Azar, 1988; Sanner and Azar, 1994; Ventresca *et al.*, 1995). Polymer filtrates that are stable at circulating temperatures, but already potentially damaging, can decompose and form residues when exposed to static reservoir temperatures for long periods of time (Tuttle and Barkman, 1974), as previously discussed.

**Table 14-6. Depth of filtrate invasion (Simpson, 1974).**

Time (D)	Depth of Invasion (in.)		
	Oil-Base Mud	Low-Colloid Oil-Base Mud	Water-Base Mud
1	1.2	3.3	7.7
5	4.6	11	12
10	7.7	17	18
15	10	21	23
20	12	23	27
25	14	29	31
30	16	32	34

## 14-4.2. Cementing

- Washes and spacers

The removal of drilling mud, while necessary for improving cement bonding, typically exacerbates formation damage through either increased fluid loss or incompatibility problems with cement washes and spacers.

The duration of a cementing job is short compared with the duration of drilling through a pay zone. The maximum depth of invasion by the filtrate from either spacers or cement slurries is a few inches, which is negligible compared to the few feet of drilling mud filtrate invasion. This does not mean that cement or spacer fluid loss should be neglected. Poor fluid-loss control can result in premature job failure by either complete loss of the preflush fluids (insufficient volumes) and subsequent contamination (and strong gelling) of the cement slurry by the drilling fluid or dehydration of the cement slurry itself.

- Cement slurries

The broad particle-size distribution of cement grains, together with the use of high-efficiency fluid-loss agents, results in limited particle and filtrate invasion of cement slurries (Jones *et al.*, 1991b). However, there are four cases where large permeability impairments can occur:

- The relatively high pH value of cement slurry filtrates is particularly detrimental to formation clay minerals. Calcium ions liberated by cement particles are quickly exchanged on clays near the wellbore, and the resulting modification of the filtrate composition makes it a perfect destabilizing fluid in terms of dispersing ability (Cunningham and Smith, 1968).
- Cement filtrate that comes into contact with connate brines that contain high concentrations of calcium can provoke the precipitation of calcium carbonate, lime (Records and Ritter, 1978) or calcium silicate hydrate (Krueger, 1986).
- Overdispersed slurries (with no yield value) promote the rapid separation of cement particles at the bottom and water at the top of the cement column. A large invasion of free water will most likely take place, and the resulting water blockage may be significant.

- Loss of cement to the natural fracture system is a catastrophic problem when using a cased and perforated completion through formations with natural fracture systems. In side-by-side well comparisons, cement loss in natural fractures in the pay zone has been shown to decrease production to the point where the zone cannot flow effectively. Once cement is lost into the fracture system, hydraulic fracturing or sidetracking and redrilling the well are the best alternatives. In some carbonate formations, acid fracturing may be beneficial.

## 14-4.3. Perforating

Perforations are the entry point from the formation to the wellbore, and all flow in a cased, perforated completion must pass through these tunnels. Although perforation job quality is at times overlooked in the search for reasons why a well does not produce as expected, any time that formation damage is suspected the perforations should be examined first. Perforating is always a cause of additional damage (Suman, 1972). Extreme overbalance (EOB) perforating has been used expressly to reduce damage to the perforation tunnels (see Chapter 11).

- Perforating mildly overbalance always forces formation and gun debris into perforation walls and decreases the permeability near the perforations (Keese and Oden, 1976).
- Perforating mildly overbalance in fluids that contain particles produces a similar effect (Paul and Plonka, 1973; Wendorff, 1974) and also builds a dense, impermeable cake on the perforation walls.
- Insufficient perforation penetration does not bypass drilling damage (Klotz *et al.*, 1974; Weeks, 1974). Penetration also decreases with formation effective stress (Saucier and Lands, 1978), a definite concern in deep wells.
- If the underbalance pressure required to achieve damage-free perforations is incorrectly estimated, the insufficient pressure difference will limit damage removal (Hsia and Behrmann, 1991; Behrmann, 1995; Bird and Dunmore, 1995), whereas excessive pressure differences lead to sand influx in the wellbore (King *et al.*, 1985; Seanard, 1986).

- Low perforation density restricts flow.

The perforating guns and processes should leave adequate entrance holes for the amount of fluid flowing into the wellbore. This can range from one shot every other foot in low-rate, homogenous formations (high vertical permeability) to as many as 12 to 16 shots per foot (spf). Most formations differ in vertical to horizontal permeability, with horizontal permeability from 3 to more than 10 times the vertical permeability. This property makes perforation density critical, especially if there are shale laminations in the pay zone. If too few perforations are used in a laminated or highly structured zone (many vertical permeability barriers), then flow from the zone will be only a fraction of what an openhole completion could be.

#### 14-4.4. Gravel packing

Formation damage mechanisms can affect gravel packs. Gravel packs are sand-exclusion techniques, essentially filters, in front of which formation fines are expected to bridge. It is almost universally true that gravel packs deteriorate with time, causing a progressive reduction of well performance. This is in contrast to current methods of sand production control and high-permeability fracturing (called frac and pack), in which well performance improves with time.

Major sources of damage in gravel packs are

- improper placement of the gravel pack (perforations remain empty or the annulus between casing and screen is incompletely filled), allowing perforation filling by formation sand, pack fluidization and subsequent intermixing of sand and gravel in the case of pressure surges (Stadlman *et al.*, 1985; Jones *et al.*, 1991a; Chuah *et al.*, 1994)
- damage by unbroken gels or formation particles during placement as a result of incomplete perforation cleaning (Sparlin, 1974)
- invasion by loss-control materials (LCM) (Blanton, 1992; McLeod and Minarovic, 1994; Hodge *et al.*, 1995)
- thread dope, paint, rust and polymer residues forced between formation sand and the gravel pack during placement
- inadequate gravel size, leading to gravel-pack invasion by formation fines during production (Gulati and Maly, 1975)

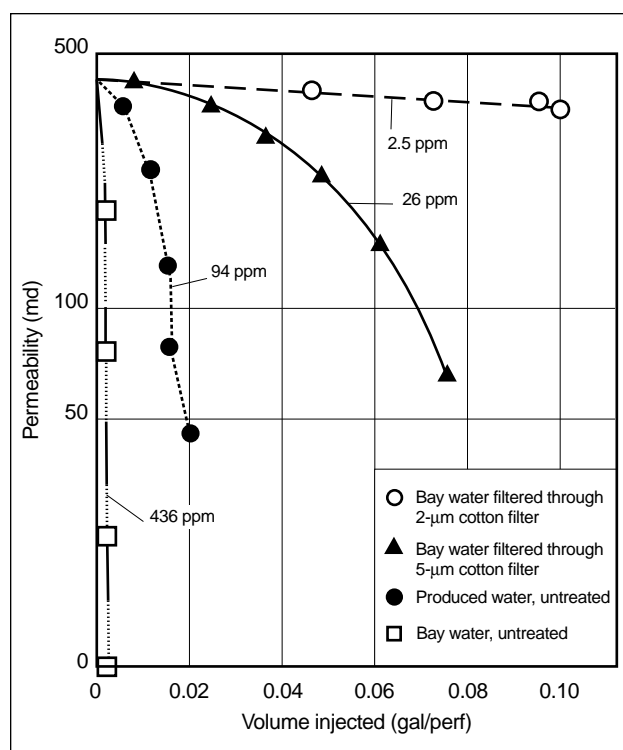
- screens with slots too large (do not retain gravel) (Flanigan, 1980) or with slots too narrow that become plugged and reduce production.

#### 14-4.5. Workovers

The various types of damage from completion and workover fluids are similar to the damage created by drilling fluids (Eaton and Smithey, 1971; Patton and Phelan, 1985):

- permeability impairment of formation rocks and productivity impairment of perforations by suspended solids (Rike, 1980; Rike and Pledger, 1981) including bacteria and polymer residues (Lissant, 1974)
- common problems resulting from filtrate invasion: clay swelling and dispersion (Azari and Leimkuhler, 1990a, 1990b), water blocks (Oudemans *et al.*, 1994) and emulsion blocks, and scale precipitation.

The necessity of using clean, filtered workover fluids has long been recognized (Fig. 14-7). Techniques to place these fluids adequately without contamin-



**Figure 14-7.** Apparent permeability reduction in Cypress sandstone cores with the injection of various filtered and unfiltered waters (Tuttle and Barkman, 1974).

ating them with the various particulate or gumlike materials in the wellbore (including thread dope) have also been proposed (Krause, 1986).

There is a strong requirement for fluid-loss control, especially in depleted reservoirs, and additives have been developed for this purpose (Crowe and Cryar, 1975; Mahajan and Barron, 1980). Another approach is to use foams, gases (Dahlgaard, 1983) or mists as completion fluids (Millhone, 1983). Instead of physically reducing the extent of filtrate invasion, the fluid-loss agents can deliberately be removed from workover fluids. In this approach, the compatibility of the fluid with formation minerals and brine must be carefully studied (Morgenthaler, 1986).

Workover brines (especially high-density brines) usually require inhibitors to control corrosion. These products can contribute to emulsion-block problems through the wettability modification of formation minerals and sometimes promote iron precipitation in the reservoir (Potter, 1984).

#### 14-4.6. Stimulation and remedial treatments

- Wellbore cleanup

When wells are cleaned to remove deposits or corrosion products from the tubing, high concentrations of damaging materials may invade the pay zone. Extreme care should be devoted to preventing these suspensions from being forced into the porous medium. Particularly dangerous are compounds that are soluble in the cleaning fluid because they cannot form impermeable cakes that prevent formation invasion. Rust in acid (Gougler *et al.*, 1985) or paraffins in hot oil (Newberry and Barker, 1985) are the two most typical redissolved wellbore compounds. They reprecipitate in the formation and cause extensive, severe and usually permanent damage.

- Acid treatments

Problems already encountered in other phases of the life of a well may also occur during acidizing treatments, especially in cases of inappropriate design. These include

- damaging materials from the tubing entering the formation rock

- oil-wetting of the reservoir by surfactants, especially corrosion inhibitors (Crowe and Minor, 1982), which can create emulsion blocks
- water blocks
- asphaltene/paraffin deposition when large volumes of acid are injected.

In addition to these common damaging processes, specific production impairment can result from poor design of acidizing treatments. These impairments include the following:

- sludges produced by reaction between acids and asphaltenes (Moore *et al.*, 1965; Houchin *et al.*, 1990), especially in the presence of some additives (particularly surfactants) (Knobloch *et al.*, 1978) or dissolved iron (Jacobs and Thorne, 1986)
- deconsolidation of the formation rock caused by excessive dissolution of the cementing materials by acids
- precipitation of by-products from the reaction of acids with formation minerals (Boyer and Wu, 1983; Gadiyar and Civan, 1994)
- precipitation caused by some sequestering agents added to acids to prevent iron problems if iron is suspected present (Smith *et al.*, 1969)
- permeability impairment by residues from corrosion inhibitors (Crowe and Minor, 1985) or produced through the thermal degradation of polymers, such as friction reducers (Woodroof and Anderson, 1977)
- dissolution of pack sands, to a limited extent, in hydraulically fractured and gravel-packed wells (Cheung, 1988; Yeager, 1990).

- Fracture treatments

Damage resulting from hydraulic fracturing takes two distinct forms: damage inside the fracture itself (proppant-pack damage) and damage normal to the fracture intruding into the reservoir (fracture-face damage). The first generally occurs because of inadequate breaking of the fracturing fluid polymer; the second occurs because of excessive leakoff. Depending on the reservoir permeability, the impact of these two damages varies.

For low reservoir permeability, neither one is much of a factor. As the permeability increases, proppant-pack damage (and its avoidance) becomes increasingly important, whereas damage to the reservoir face is relatively unimportant. At high permeabilities, both are important, with fracture-face damage dominating at very high permeabilities.

The selection of fracturing fluids, polymer concentrations and breakers is critical in addressing these issues. Incomplete breaking of the polymers in fracturing fluid is the most obvious cause of damage within hydraulic fractures (Gidley *et al.*, 1992), as well as the poor selection of proppant fracturing fluids (Brannon and Pulsinelli, 1990) and formation rock spalling or creeping into the proppant pack (Strickland, 1985). True damage in the formation rock is the consequence of excessive leakoff in high-permeability reservoirs when polymer-base gels are used in combination with inefficient fluid-loss agents (Elbel *et al.*, 1995; Parlar *et al.*, 1995). These damages are usually severe and usually cannot be improved with matrix treatments. To alleviate this problem, polymer-free, surfactant-base fluids have been proposed (Stewart *et al.*, 1995); however, they cannot be used in the absence of crude oil, which is required for breaking the surfactant micelles.

- Poor load-fluid recovery

Typical load-fluid recovery on a stimulation treatment or remedial treatment may range from as little as 20% to 100%. Load fluids can invade and become trapped in the formation by entering the smaller capillary pores during higher injection pressures, or they may coat clays with high micro-porosity (a condition in which a large surface area exists for water coating or trapping). Once the injection pressure is released, capillary pressure effects will hold significant volumes of the fluid in the formation. In some formations, more than 50% of the load fluid can be trapped after a treatment, and yet the formation may not appear damaged. Most of the flow is through the larger pore system and natural fractures, and these passages usually clean out quickly. The smaller pore passages can trap fluid by imbibing or absorbing it, but they have no real effect on the flow through the formation.

#### 14-4.7. Normal production or injection operations

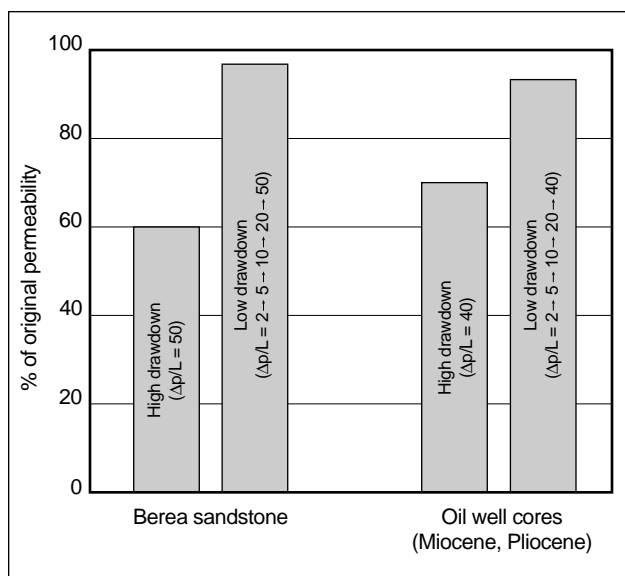
- Unconsolidated formations

Formations that are capable of releasing parts of the matrix during production or after stimulation pose special treating problems. Although these situations are commonly thought of as sand-control problems rather than formation damage, the effect of mobile sand and the pressure drop caused by collapsed formation tunnels closely resemble the effect of formation damage. Some reservoirs cannot be produced at high flow rates or large draw-downs without being affected adversely. Permanent damage, which cannot be removed simply by the reducing production rate, may be created.

A major problem is the movement of fines in the formation in response to either flow velocity or changes in the salinity of the flowing fluid. Although this subject was addressed in Section 14-3.1, it is worth mentioning again, because it is usually a significant factor in the behavior of unstable formations. Native silts and clays loosely attached to pore walls can be put into motion by high flow rates (Hower, 1974; Holub *et al.*, 1974), especially when two or more immiscible fluids are produced at the same time (Muecke, 1979; Sengupta *et al.*, 1982). Depending on their particle size, they can either block pore throats in the vicinity of their initial location or migrate toward the wellbore.

Whether migrating particles reach the wellbore or bridge over pore throat entrances depends on their original concentration in the formation, their size, the extent of the increase of their concentration near the wellbore (because of radial flow) and the maximum flow rate (Vaidya and Fogler, 1990; Gunter *et al.*, 1992; Oyenenin *et al.*, 1995). Bridging is promoted when one or more of these parameters are increased. Bridging is less detrimental than blocking because a short period of reverse flow, followed by production at a flow rate lower than that at which bridging occurred, may mechanically disperse bridges (Fig. 14-8). However, this cannot be achieved when the bridging agglomerates were previously cemented by precipitates (asphaltenes or scales) or chemically stabilized through the injection of flocculants (such as clay stabilizers).

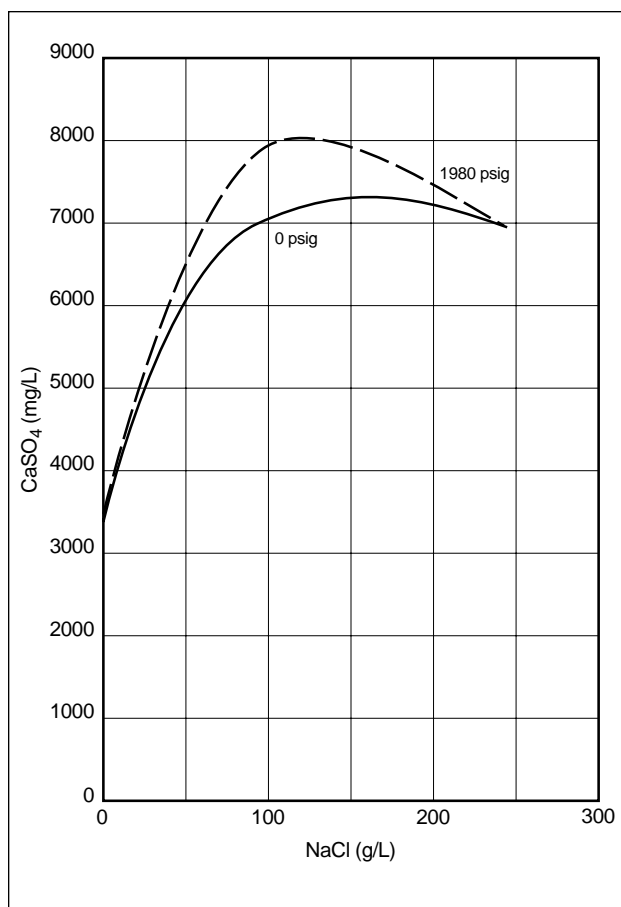




**Figure 14-8.** Effect of drawdown pressure during cleanup on the permeability regained by damaged sandstones (Krueger *et al.*, 1967).  $\Delta p$  = pressure difference,  $L$  = length.

Excessive drawdown can also decrease pore pressure near the wellbore to such an extent that the effective stress exceeds the formation rock compressive strength. This phenomenon is obvious in poorly cemented sandstones, where wellbore filling by formation sand is progressive (Stein and Hilchie, 1972; Stein *et al.*, 1974; Antheunis *et al.*, 1979). It is less apparent in chalks, where formation compaction and significant porosity reduction affect the near-wellbore region without any occurrence of formation debris in the produced fluids (Morita *et al.*, 1984; Blanton, 1978; Ben Marek, 1979; Van Ditzhuijzen and de Waal, 1984). Chalk compaction is four- to eightfold greater when soft waters are injected during completion (Newman, 1983). Formation breakage is particularly damaging in hydraulically fractured wells, where creeping inside the proppant pack results in large-scale drops in production (Strickland, 1985). It has to be emphasized that once created, this type of damage cannot be removed by matrix treatments.

Reduction in the pore pressure during production (Fig. 14-9) (Fulford, 1968), and sometimes cooling resulting from gas expansion, results in the precipitation of organic (Hirschberg *et al.*, 1984; McClafin and Whitfill, 1983; Schantz and Stephenson, 1991; Singhal *et al.*, 1991; Leontaritis *et al.*, 1992; Takhar *et al.*, 1995; Piro *et al.*, 1995) or inorganic materials. Generally, these deposits



**Figure 14-9.** Pressure effect on gypsum scale solubility at 95°F [35°C] (Fulford, 1968).

affect only the production string and surface equipment. However, they can reduce formation permeability. Seeds, such as high-surface-area clays, promote the deposition of organic materials (especially asphaltenes) (Rogers, 1976) or the precipitation of supersaturated salt solutions.

Common scales are calcium carbonate (Vetter and Kandarpa, 1980; Nancollas and Sawada, 1982; Gudmundson and Ortiz-R., 1984) and calcium sulfate (Vetter and Phillips, 1970; Oddo *et al.*, 1991; Lejon *et al.*, 1995). Problems associated with the deposition of elemental sulfur (Kuo, 1972), sodium chloride (Place and Smith, 1984) and barium sulfate (Wat *et al.*, 1992) have also been described. Commingled precipitation of asphaltene and calcium carbonate is common (Efthim *et al.*, 1990).

Special cases of spalling or sloughing of particles from brittle formations are also problems. These particles are derived from tensile failure created during flow that results in chips of the forma-

tion spalling into the perforations or the wellbore. Brittle formation behavior is seen typically in hard dolomites, brittle shales and a few shaly sandstones. Brittle formation failure is generally created by stresses in the formation and confining stresses caused by depletion. Prevention of these stresses is difficult without repressuring the reservoir.

- Retrograde condensation and two-phase flow  
Retrograde condensation and bubblepoint problems are relative permeability blocking problems. Retrograde condensation is the condensation of a liquid from gas. When this happens, the relative permeability to gas can be reduced substantially. In oil reservoirs produced below the bubblepoint pressure, free gas is formed, which reduces the relative permeability to oil.

## 14-5. Laboratory identification and treatment selection

The objectives of laboratory experiments are to identify potential damage and aid selection of the optimum treatment fluid and design. To achieve these objectives, the formation material (cores), produced fluids and damaged material must be analyzed. Definitive core flow studies and solubility tests are usually required to identify the source of damage and to help determine the best procedure for damage removal.

### 14-5.1. Damage identification

- Core analysis  
The detailed analysis of formation cores is required to design the damage removal treatment. It is difficult to determine formation mineralogy without the use of cores (sidewall or conventional). Conventional cores are recommended to complete the analysis because sidewall cores can be contaminated with drilling fluids and may not be representative of the formation. If sidewall cores are used, the analysis should be conducted on duplicate cores.
- Formation mineralogy  
The formation mineralogy is an important parameter affecting stimulation success. Knowledge of the petrography of the formation is essential to

understanding what the response of the rock (formation material) will be to any fluid. The relation between the rock and the treating fluid depends on the minerals present and the position of the minerals within the rock matrix. The analytical techniques used to characterize the mineralogy are X-ray diffraction (XRD), SEM and thin-section analysis.

XRD analysis provides rapid and accurate identification of the crystalline material of the rock matrix. Each crystalline material has a specific XRD pattern. The types and quantities of clays and feldspars can be qualitatively determined using XRD. Crystalline scale deposits can also be identified using XRD.

SEM provides information on mineralogy and morphology and the size of pore-lining materials. Quantitative elemental analysis and mineral identification can be achieved by using this technique in conjunction with energy-dispersive spectrophotometry (EDS). The primary advantages of SEM-EDS analysis over light microscopy are the depth of focus and magnification. The techniques are useful for observing clay platelet structure and analyses. The structures of smectite, kaolinite, chlorite and illite are shown in Fig. 14-4.

Thin-section analysis is used widely to study rock structure and quantify minerals. In addition, cementing minerals and the types and location of pores can be identified. The rock is impregnated with a blue-colored resin to fill the interconnected porosity. A thin (approximately 30  $\mu\text{m}$  in thickness) slice is cut perpendicular to the bedding plane, and the surfaces are polished. Using a polarized microscope, the minerals can be observed by transmitted light because they have characteristic optical properties. The pore structure is easily identified by the blue resin.

- Formation wettability  
Most formations (sandstone or carbonates) are water-wet. Occasionally, oil-wet formations are encountered, especially when the produced oil is a low-gravity oil. In some situations, the formation appears to be oil-wet because of the produced oil and the natural surfactants present in the oil; however, when the oil is removed using appropriate solvents, the formation may be water-wet. When the oil adheres to the rock matrix strongly, it must be removed prior to mineralogy or reactivity test-

ing. If the formation material is coated with oil, it should be cleaned with an aromatic solvent such as xylene until all traces of oil have been removed and followed with a xylene- and water-miscible solvent such as methanol.

The simplest test to determine formation wettability is to take approximately 10 cm<sup>3</sup> of formation material and place it in the produced brine to equilibrate for approximately 30 min. The formation material is then placed in an oil (such as kerosene) and observed. To accentuate the test results, red dye can be added to the clear oil to aid identification of the oil adhering to the formation material. After it is allowed to equilibrate for an additional 30 min, the formation material is added to a fresh aqueous solution. Strongly water-wet formations or other fines disperse readily in aqueous fluids but agglomerate or clump together in the clear oil-base fluids. Conversely, oil-wet particles disperse in oil but agglomerate in water-base fluids. The surface is water-wet if the contact angle of the fluid with the formation material is less than 90°; the surface is oil-wet if the contact angle is greater than or equal to 90°. Wettability can exist in various degrees between extremely water-wet and extremely oil-wet. Intermediate wettability is difficult to identify and describe, with contact angles greater than 80° but less than 100°.

The wettability test can also be used to determine if the desired treatment fluid is water-wetting or oil-wetting and how the treatment fluid may affect the desired natural wettability. The cleaned formation material is treated as described previously except the formation material is placed in the desired treatment fluid instead of naturally produced brine. Changes in wettability resulting from the selected treatment fluid can be detected using this method.

- **Petrophysical characterization**

Core porosity and permeability should be measured before performing a core flow evaluation.

- **Porosity**

Porosity is the ratio of the void space volume to the bulk volume of the rock material. It is a measure of the volume occupied by oil, gas and other fluids in the reservoir. Total, effective and residual porosities are defined in Chapter 1.

The porosity of the rock sample can be determined using one of several techniques. The simplest technique for the determination of effective porosity uses Boyle's law; the pressure of nitrogen is determined in a constant-volume cell, with and without the core. The total porosity is derived by bulk and matrix density measurements with a helium pycnometer. When required, the pore-size distribution can also be measured using a mercury intrusion porosimeter. The size and number of pores can be calculated and the microporosity can be estimated. The microporosity can be more accurately determined using the Brunauer, Emmett, Teller (BET) gas adsorption technique if required.

- **Permeability**

Permeability, an intrinsic characteristic of the rock, is a measure of the rock's capacity to transmit fluids. The measurement is usually made with gas (e.g., nitrogen [N<sub>2</sub>]) or liquids (e.g., brines and oils).

Permeabilities must be determined using simulated downhole temperature and stress conditions. In certain stress-sensitive formations, permeability determined under 1,000-psi confining stress may be 1 order of magnitude higher than the permeability determined at 10,000-psi stress.

- **Formation fluid analysis**

Analysis of the formation brine and oil can aid in determining the types of damage that may be present.

- **Brine**

Analysis of the formation brine can be used to predict scale formation. Common ions are listed in Table 14-7. Their presence can be determined using standard laboratory wet-chemical or instrumentation techniques.

**Table 14-7. Common ions in formation brines.**

Cations	Anions
Sodium (Na <sup>+</sup> )	Chloride (Cl <sup>-</sup> )
Potassium (K <sup>+</sup> )	Bicarbonate (HCO <sub>3</sub> <sup>-</sup> )
Calcium (Ca <sup>2+</sup> )	Carbonate (CO <sub>3</sub> <sup>2-</sup> )
Magnesium (Mg <sup>2+</sup> )	Sulfate (SO <sub>4</sub> <sup>2-</sup> )
Barium (Ba <sup>2+</sup> )	
Strontium (Sr <sup>2+</sup> )	
Iron (Fe <sup>2+</sup> and Fe <sup>3+</sup> )	

Calculations are available to predict scaling tendencies. The intermixing of produced brines with spent acid can result in the formation of insoluble precipitates. Analysis of these brine data aids in selecting the treatment fluids and their sequence.

– Oil

Analysis and testing of the produced oil can also help stimulation treatment design. The use of treating fluids that are incompatible with the produced oil can result in the formation of emulsions and sludge that will subsequently result in an unacceptable response to the stimulation treatment. The oil may contain paraffins and asphaltenes that can interact with the treatment fluid. The quantity of various fractions of asphaltenes and paraffins and their ratio to each other are used to assess the possibility of organic precipitation damage. It is also imperative that the identity of deposits recovered from a well be determined. This is particularly true of organic deposits because treatments for paraffin and asphaltene removal are different.

A test of the API gravity is performed on the produced oil to evaluate sludging tendencies. Certified hydrometers are used to measure the specific gravity as a function of temperature.

For analysis of the asphaltene content, the produced oil is centrifuged to separate out emulsified aqueous fluids. Mixing the crude oil with pentane and centrifuging the sample enables preferential separation of asphaltenes from the produced fluid. Repeated extraction is performed until all oil has been removed. The precipitated asphaltene material is collected, and standard laboratory techniques are used to obtain the content by weight. The oil pentane fraction is saved and the pentane solvent is evaporated. The residual oil is then used to complete the analysis for the paraffin content.

For analysis of the paraffin content, a sample of vigorously mixed crude oil and acetone is centrifuged to enable preferential extraction of the paraffin material into acetone. Repeated extraction and holding at temperatures less than 32°F [0°C] result in precipitation of the paraffins. The acetone mixture is filtered to remove the paraffins, which are dried to remove residual acetone. On the basis of the total composition of the pro-

duced oil used for the analysis, the percentage of paraffin is determined.

## 14-5.2. Treatment selection

The solubility of the formation or damage material, treating fluid compatibility and core flow studies should be conducted to aid designing the best treatment for damage removal and to select the chemical products that are the most compatible.

- Solubility tests

- Formation material

Calcite, dolomite and ankerite are soluble in HCl and mud acid systems. Clay and silt are soluble only in mud acid systems. Because of their high surface area, clays and other fines are much more reactive with mud acid than sand grains are. The total solubility of the formation material is the sum of the solubility of each mineral in the formation sample. Minerals other than carbonates are also soluble in HCl; therefore, solubilities should be used with caution. These minerals include sulfates (e.g., anhydrite), iron oxides and halite. The solubilities of common minerals are shown in Table 14-8.

Solubility tests are performed under ideal laboratory conditions and therefore exhibit the maximum formation solubility. The structure of the rock and the position of each mineral in relation to the flow paths in the rock matrix may result in different solubilities during actual acidizing operations. Solubility determined in the laboratory is not a definitive value for the maximum solubility that may result during the acidizing process, but it provides guidelines as to which treating fluids are most applicable.

A combination of solubility test results and XRD is commonly used to estimate the carbonate, silt and clay minerals and other mineral contents in the rock matrix. Determination of the acid solubilities of the various materials in HCl and mud acid determines the total solubility. When the results are used in conjunction with XRD analysis, the composition can be determined by the following procedure.

1. The total solubility in HCl is typically used as an estimate of the total carbonate content.

**Table 14-8. Solubility of common minerals in acids.**

Mineral	Chemical Composition	Solubility	
		HCl	HF
Quartz	SiO <sub>2</sub>	None	Low
Feldspar			
Microcline	KAlSi <sub>3</sub> O <sub>8</sub>	None	Moderate
Orthoclase	KAlSi <sub>3</sub> O <sub>8</sub>	None	Moderate
Albite	NaAlSi <sub>3</sub> O <sub>8</sub>	Very low	Moderate
Plagioclase	(Na,Ca)Al(Si,Al)Si <sub>2</sub> O <sub>8</sub>	Very low	Moderate
Mica			
Biotite	K(Mg,Fe <sup>2+</sup> ) <sub>3</sub> (Al,Fe <sup>3+</sup> )Si <sub>3</sub> O <sub>10</sub> (OH) <sub>2</sub>	Low	Moderate
Muscovite	KAl <sub>2</sub> (AlSi <sub>3</sub> )O <sub>10</sub> (OH) <sub>2</sub>	Low	Moderate
Clay			
Kaolinite	Al <sub>2</sub> Si <sub>2</sub> O <sub>5</sub> (OH) <sub>4</sub>	Low	High
Illite	(H <sub>3</sub> O,K) <sub>y</sub> (Al <sub>4</sub> • Fe <sub>4</sub> • Mg <sub>4</sub> • Mg <sub>6</sub> )(Si <sub>8-y</sub> • Al <sub>y</sub> )O <sub>20</sub> (OH) <sub>4</sub>	Low	High
Chlorite	(Mg,Fe <sup>2+</sup> ,Fe <sup>3+</sup> )AlSi <sub>3</sub> O <sub>10</sub> (OH) <sub>8</sub>	Moderate	High
Smectite	(Ca <sub>0.5</sub> Na) <sub>0.7</sub> (Al,Mg,Fe) <sub>4</sub> (Si,Al) <sub>8</sub> O <sub>20</sub> (OH) <sub>4</sub> • nH <sub>2</sub> O	Low	High
Mixed layers	Kaolinite, illite or chlorite layered with smectite		
Carbonate			
Calcite	CaCO <sub>3</sub>	High	High <sup>†</sup>
Dolomite	CaMg(CO <sub>3</sub> ) <sub>2</sub>	High	High <sup>†</sup>
Ankerite	Ca(Fe,Mg,Mn)(CO <sub>3</sub> ) <sub>2</sub>	High	High <sup>†</sup>
Sulfate			
Gypsum	CaSO <sub>4</sub> • 2H <sub>2</sub> O	Moderate	High
Anhydrite	CaSO <sub>4</sub>	Moderate	High
Other			
Halite	NaCl	High	High
Iron oxide	Hematite (Fe <sub>2</sub> O <sub>3</sub> ), goethite (α-FeO(OH)), magnetite (Fe <sub>3</sub> O <sub>4</sub> ), siderite (FeCO <sub>3</sub> )	High	High
<sup>†</sup> Precipitation of CaF <sub>2</sub>			

- The solubility of the formation material in mud acid is used to determine the silt and clay content (total fines) and the carbonate content.
- The difference between the solubilities in mud acid and HCl is considered the approximate content of clay and fines.
- The total reactive silt content is calculated as the difference between the silt and clay content determined by solubility and the total clay content determined by XRD.

- Other minerals that are soluble in the acid should also be determined and confirmed by XRD.

– Scales

The solubility of scale deposits depends on the mineralogy of the rock. Tests similar to the tests performed to determine formation solubility can be performed to determine the best solvent for scale removal. Identification of the deposit by XRD prior to the solubility evaluation is recommended to aid selecting the most active solvent.

Typically, acids, chelating agents or mechanical systems are used for removal. These tests should be performed under simulated well conditions to determine the optimum treatment.

- Organic deposits

Solubility tests at temperature and pressure can be performed to evaluate the most effective solvent to remove the plugging deposit. Typically, paraffin, asphaltene and tar deposits are soluble in aromatic solvents such as xylene or toluene; however, most deposits are a combined deposit and may require a combined treatment of an organic solvent with acid and other surface-active agents to improve the wettability of the deposit and enhance the dissolving capacity of the selected treatment fluid. Other solvents, such as mutual solvents and alcohols, may also aid the removal of an organic deposit.

- Bacterial slime

Bacterial slime is also removed by treating with solvents. These deposits are soluble in water containing oxidizing agents such as sodium hypochlorite. If required, solubility tests can be performed to evaluate the efficiency of the oxidizing agent. Tests should be performed using simulated downhole conditions, if possible.

- Treating fluid–formation compatibility

Preventing emulsion and sludge formation following a damage-removal treatment requires an optimum fluid design to minimize or eliminate the formation of precipitates. The potential for the formation of acid and produced crude oil emulsions and optimization of the de-emulsifier treatment are currently evaluated using American Petroleum Institute (API) *Recommended Practices for Laboratory Testing of Surface Active Agents for Well Stimulation* (RP 42) (1977).

- Emulsion prevention testing

Prior to a stimulation treatment, the compatibility of the treatment fluid with the produced oil must be determined. Fine siliceous materials, ferric iron or both can be added to evaluate emulsion stability mechanisms. These fluid interactions can produce downhole emulsion problems. The quantity of additives used to control emulsion stability and sludge formation

must be established. Additives such as corrosion inhibitors, surfactants and mutual solvents must also be included in the desired acid formulation for compatibility testing. The concentrations of these additives are established by core flow tests, metallurgy and the well conditions that occur during treatment.

Acid, or another aqueous treating fluid, is mixed with fresh crude oil (at low energy to simulate downhole mixing) in a glass container and observed at bottomhole temperature, if possible. The characteristics and time for emulsion breakout are determined. The quantity of aqueous fluid breakout is determined at set time intervals. The sample that provides the most rapid emulsion breakout is desired. The acid system is modified, including the type and quantity of nonemulsifier, until the minimum aqueous breakout time is achieved. A clean oil/water interface and rapid emulsion break (less than 10 min) are desired. The oil phase must also be clear, with no emulsified water draining freely from the glass surface (signifying a water-wet surface).

Differences in emulsion stability are attributed to more dominant factors such as stabilization by solids precipitation (organic and inorganic), ferric ion interaction with the asphaltene component of crude oil and viscosity increase at the interface. Results presented by Coppel (1975) show that partially spent acids contain potentially precipitable materials in solution. As the pH value of the spent acid increases during flowback and mixes with other produced fluids, materials precipitate that can stabilize emulsions. Dunlap and Houchin (1990) recommended using polarized microscopy to evaluate return fluids to establish the cause for a stabilized emulsion. Specific damage mechanisms such as emulsion stabilization by organic deposits, solids and iron may be detected and identified. Stabilization by solids can be evaluated by the use of fine silica or clay in the emulsion test described previously.

Downhole emulsions can be attributed to inadequate prejob compatibility testing because the additives used in the acid system may preferentially adsorb onto the rock matrix or partition to the oil phase during production. Alternate testing procedures have been recommended to simulate reservoir conditions more accurately.

Ali *et al.* (1994) recommended using an alternate procedure that better simulates downhole intermixing of the stimulation fluids and the produced crude. The formulated acid containing inhibitor, surfactants, mutual solvents and non-emulsifiers is filtered through a sand pack containing 10% silica flour, 10% clays (such as montmorillonite) and 80% 100-mesh sand prior to completion of the emulsion test. This procedure simulates the filtration of the acid system within the rock matrix. Surfactants, such as those used in nonemulsifiers, are adsorbed onto the mineral surfaces. This adsorption minimizes the availability of the surfactants in solution to prevent emulsions.

#### – Sludge prevention testing

Prior to the stimulation treatment, the compatibility of the treating fluid with the produced oil must be determined for sludging tendencies. Interaction of the acid with crude oil can generate the formation of solid precipitates, although the system does not form stable emulsions. These precipitates are sludge and are insoluble in the hot formation oil or brine. The sludging tendencies are aggravated by intermixing with ferric iron. If not prevented, precipitated solids can result in decreased production following an acid treatment.

The sludging evaluation is similar to the emulsion test previously described. The oil should be free of solids and emulsified water. Following completion of the emulsion test, the acid and oil mixture is maintained at the bottomhole temperature for 1 to 4 hr. The mixture is then filtered through a 100-mesh screen, and the precipitated sludge on the filter is identified.

To eliminate the formation of sludge, the acid system must contain an antisludge additive. The concentration of antisludge additive is increased in the acid system until formation of the sludge precipitate is eliminated.

#### • Core flow tests

Core flow tests are used to determine the effects of treatment fluids on formation samples at simulated well treating conditions. The structure of the rock and the position of each mineral in relation to the flow channels in the rock matrix may result in different solubilities during actual acidizing opera-

tions. Therefore, the permeability changes depend on the dissolution and precipitation reactions that occur. Observations that indicate what dissolves and what precipitates are extremely useful in selecting the best treatment fluid.

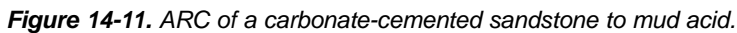
The effects of sequential injection of the different treatment fluids can also be observed. Fluid injection rates range from 0.2 to 10 mL/min and pressures range up to 1500 psi. Flow rates should be selected to ensure that the fluid movement has minimal effect on the movement of fines contained within the pore structure. The 1-in. diameter, 12-in. long cores are placed in a core holder and confined under pressure to simulate reservoir stresses. To ensure fluid flow through the core, the confinement pressure should be greater than the pressure required to initiate flow through the core. Tests should also be performed with backpressure. For core flow studies of acids, a backpressure of at least 1000 psi is required to maintain the CO<sub>2</sub> produced by acid dissolution of carbonate deposits in solution. For scale and deposit removal, sufficient backpressure is required to prevent vaporization of the treating fluid. The diagram of the core flow apparatus is shown in Fig. 14-10.

The results of these tests are shown by an acid response curve (ARC), as illustrated in Fig. 14-11. The evolution of permeability versus the volume of treating fluids is determined and the effect of each fluid on the core permeability is calculated and displayed. Core holders utilizing multiple pressure taps can be used to examine the effect of each fluid as it penetrates deeper into the formation.

Permeability changes depend on dissolution and precipitation reactions. Tests to determine what dissolves and what precipitates are not used to determine treatment volumes, which depend on the type and extent of damage. If formation cores are used for the study, they should be cleaned with aqueous alcohol or ethylene glycol monobutyl ether solutions to remove traces of oil and ensure that the cores are water-wet.

## 14-6. Treatment strategies and concerns

Once the damage and its origin have been characterized, the correct remedial action can be taken. Various types of damage can coexist because almost





every operation performed on the well (drilling, completion, workover, production and stimulation) is a potential source of damage (Krueger, 1986).

The efficiency of a matrix treatment in sandstones depends primarily on removing the damage affecting productivity or injectivity (Williams *et al.*, 1979). This restriction is usually shown by an overall lower level of or sharper than expected decline in production. The extent of damage is typically estimated using pressure transient analysis.

The physical characteristics, not the origin, of the damage determine the treating fluid. A fluid can be used to treat occurrences of the same type of damage, regardless of what caused the damage. Seven basic types of damage are shown in Fig. 14-12.

When formation damage has reduced the productivity of a well, matrix acidizing is usually the appropriate treatment, though reperforating with deeper penetrating holes may be a ready alternative for shallow damage. Typically, formation damage is associated with partial plugging of the rock matrix around the wellbore. The objective of matrix acidizing is to remove the damage or bypass it by creating channels, such as wormholes. When matrix acidizing or reperforating is not possible, a short proppant fracturing treatment can be an alternative.

Matrix acidizing treatments remove damage by injecting reactive fluids into the natural porosity of

the reservoir at “matrix” (subfracturing) rates and pressures. These relatively low rates and pressures are necessary to remove the damage located in the near-wellbore area. The flow rate is also limited to prevent fracturing of the formation, which would result in the loss of treatment fluid behind the damaged zone.

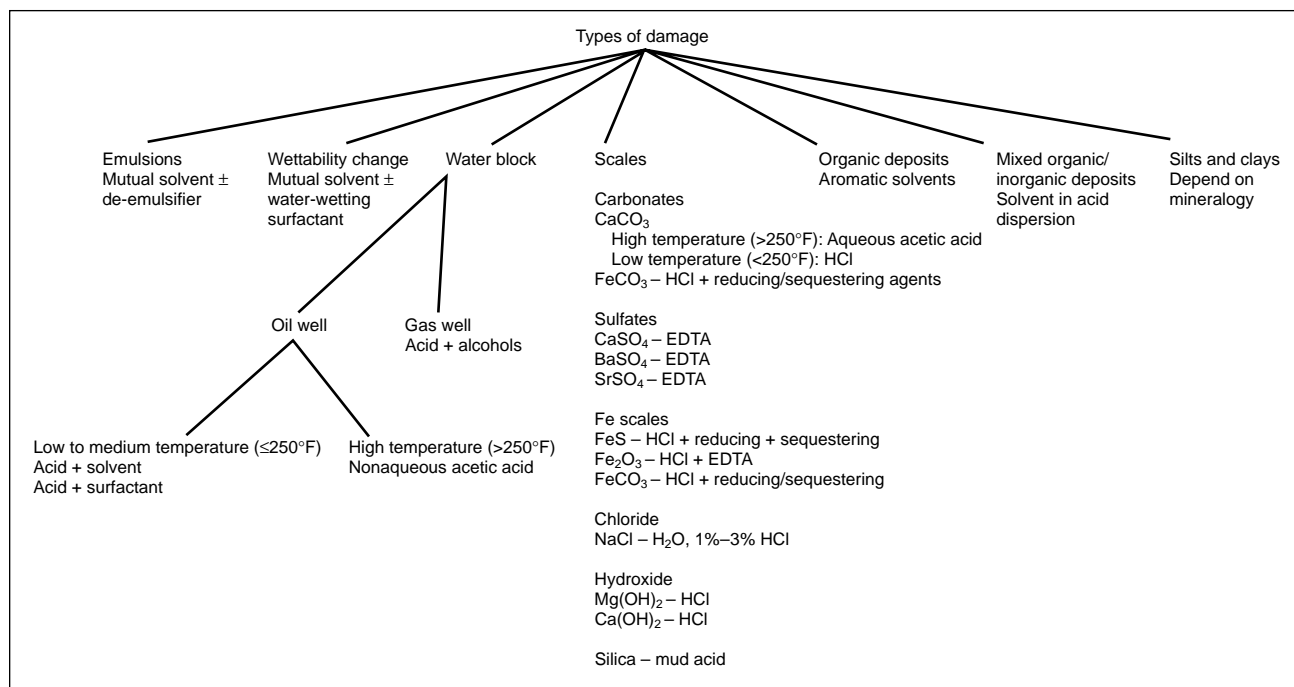
Inexpensive and readily available inorganic acids, such as HCl or hydrofluoric acid (HF), are used to dissolve some of the damaging materials, rock constituents or both. A certain volume of acid is pumped into the formation to restore near-well permeability (sandstones) or to increase rock permeability (carbonates).

Treatment strategies for the various formation damages discussed previously are reviewed in the following sections. In addition, strategies for some common types of wellbore damage are discussed.

### 14-6.1. Fines and clays

- Migrating fines

The treatment of moveable fines can be accomplished by either prevention (using a clay-control process) or removal. Removal of migrating fines in sandstone formations is best accomplished by treatment with a fluid containing HF and HCl mix-



**Figure 14-12.** Treatment selection and the nature of damage.

tures—these are the commonly used mud acids. Deeply penetrating acid systems, containing fluoboric acid, show a good possibility for particle destruction and extend some potential for clay stabilization. Fracturing the formation is also a treatment possibility because the effect from linear flow in the walls of the fracture has a less detrimental effect on production than inward radial flow in an unfractured well. The success of both clay control and fines removal depends on the depth extent of the fines movement problem. In many cases, tip-screenout (TSO) fracture design using a short fracture for damage bypass is a better alternative.

HCl systems are typically used to remove fines damage in a carbonate formation. Because the fines are not dissolved, but are dispersed in natural fractures or the wormholes that are created, N<sub>2</sub> is usually recommended to aid fines removal when the well has a low bottomhole pressure.

- Swelling clays

The removal of smectite is usually accomplished with HF or fluoboric acid, depending on the depth of penetration. In the event of deep clay-swelling problems (more than 2 ft), the best treatment is usually a fracture to bypass the damage.

- Unconsolidated formations

Two basic problems determine the method of treatment for unconsolidated formations. If the formation moves as discrete large particles (i.e., the building blocks of the formation are moving), then the problem is a lack of cementation between the grains for the applied production forces, and the formation is classified as a low-strength formation. Treating low-strength formations can be difficult if the cementing materials are reactive with the fluid that is injected to remove formation damage or to improve permeability. Fortunately, the cementing materials in most formations have a small surface area and are less reactive with acids than with fines or clay particles in the pores of the rock.

When formations expel large grains into the wellbore, it may be beneficial to add additional perforations to reduce the velocity across the sandface or to design a fracture to reduce the drawdown. (It is common to fracture formations with permeabilities higher than 100 md.) These fractures are usually TSO designs that provide short, highly conductive fractures that can reduce the

drawdown and control sand movement by both pressure reduction and use of the proppant at the interface contacts of a gravel pack as an “information” gravel pack.

The treatment of spalling problems is extremely difficult. Propped fractures may help contain the formation and spread out the drawdown to reduce the spalling force, although totally halting spalling may be impossible. One of the keys to treatment selection is whether the spalling is caused by high initial pressures that will quickly deplete or by cyclic mechanical loads that will recur. If high initial pressure is the problem, a cleanout may suffice. If cycling is the problem, a permanent control method is the best solution. Control methods include gravel packing, fracture packing, selective perforating (along the fracture axis) and some plastic-bonding methods.

## 14-6.2. Scales

Various solvents dissolve scales, depending on their mineralogy. The most common treatments for the scales in a well are as follows:

- Carbonate scale (CaCO<sub>3</sub> and FeCO<sub>3</sub>)—HCl will readily dissolve all carbonate scales if the acid can penetrate to the scale location (Tyler *et al.*, 1985).
- Gypsum (CaSO<sub>4</sub> · 2H<sub>2</sub>O) or anhydrite (CaSO<sub>4</sub>)—These calcium sulfate scales are removed with compounds that convert the sulfate to a hydroxide or other ion form followed by acid or by direct dissolvers such as ethylenediaminetetraacetic acid (EDTA) or other types of agents. Following a calcium sulfate dissolver with acid may double the amount of scale dissolved because most scales are mixtures of materials and HCl has some ability to dissolve the finest particles of calcium sulfate. The tetrasodium salt of EDTA is preferred because its dissolution rate is greater at a slightly alkaline pH value; the more acidic disodium salt has also been used, as well as other strong sequestrants of the same family, although they do not show a marked difference from the EDTA performance. Care must be used not to over-run the spent scale dissolver or converter solutions with acid because massive reprecipitation of the scale will occur.
- Barite (BaSO<sub>4</sub>) or celestite (SrSO<sub>4</sub>)—These sulfate scales are much more difficult to remove, but their occurrence is more predictable. Barium and stron-

tium sulfates can also be dissolved with EDTA if the temperature is high enough and contact times are sufficient (typically a 24-hr minimum soaking time for a 12,000-ft well with a bottomhole temperature of about 212°F [100°C]; Clemmit *et al.*, 1985). Barium and strontium sulfate removal methods are usually mechanical. Most chemical removers are only slightly reactive, especially in thick deposits, but mixtures of barium sulfate and other scales can usually be removed by properly formulated dissolvers with sufficient soak times. Thick deposits should be removed by mechanical or abrasive methods. Care must be exercised when analyzing well debris to avoid mislabeling barite from drilling mud residue as barium sulfate scale.

- Sodium chloride (NaCl)—Sodium chloride scale is readily dissolved with fresh water or weak acidic (HCl, acetic) solutions. Redesigning the mechanical system to avoid heat loss and water drop-out are also treatment possibilities.
- Iron scales, such as iron sulfide (FeS) or iron oxide (Fe<sub>2</sub>O<sub>3</sub>)—HCl with reducing and sequestering (EDTA) agents dissolves these scales and prevents the reprecipitation of by-products, such as iron hydroxides and elemental sulfur (Crowe, 1985). Soak times of 30 min to 4 hr are usually beneficial in removing these scales when using acid. Where iron sulfide is a thick deposit, mechanical action such as milling is suggested. Water jetting typically will not cut an iron sulfide scale except where it is dispersed with other scales or exists as a thin coating.
- Silica scales—Silica scales generally occur as finely crystallized deposits of chalcedony or as amorphous opal and are readily dissolved by HF.
- Hydroxide scales: magnesium (Mg(OH)<sub>2</sub>) or calcium (Ca(OH)<sub>2</sub>) hydroxides—HCl or any acid that can sufficiently lower the pH value and not precipitate calcium or magnesium salts can be used to remove these deposits.

Contact time is an important factor in the design of a scale removal treatment. The major concern in treating scale deposits is allowing sufficient time for the treating fluid to reach and effectively dissolve the bulk of the scale material. The treating fluid must dissolve most of the scale for the treatment to be successful.

### 14-6.3. Organic deposits

Organic deposits are usually resolubilized by organic solvents. Blends of solvents can be tailored to a particular problem, but an aromatic solvent is an efficient, general-purpose fluid. Environmental concerns have led to the development of alternative solvents (Samuelson, 1992).

Paraffin removal can be accomplished using heat, mechanical scraping or solvents. Heating the tubing with a hot oiler may be the most common type of treatment. It may also be the most damaging and least effective in some cases. Injection of hot oil from the surface will melt the paraffin from the walls of the pipe, but the depth to which the injected fluid stays hot is a function of the well configuration. If the well is allowed to circulate up the annulus while the hot oil is injected down the tubing, the heat will not penetrate more than a few joints of tubing from the surface. The heat is quickly transferred through the steel tubing to the fluids rising in the annulus and little, if any, heat reaches deep in the well. As the hot oil cools, the paraffin picked up in the upper part of the well can precipitate. If hot oiling is required at depths greater than 150 ft, an alternate method of placement must be used. Deeper application of heat is available with other processes that feature heat generation as part of an exothermic chemical reaction. The processes require close control and are generally expensive.

Mechanical scraping can be useful in cases where extensive deposits of paraffin must be removed routinely. Scraping is usually accomplished with slickline and a cutter. In wells that utilize a rod string, placing scrapers on the string may automatically scrape the tubing walls.

Solvent treating to remove paraffin may be based around a straight- or aromatic-chain solvent. The most appropriate solvent depends on the specific paraffin and the location of the deposit. Heat (at least to 130°F [55°C]) and agitation significantly increase the rate of removal.

Removal treatments for asphaltenes use aromatic solvents such as xylene and toluene or solvents containing high percentages of aromatics. Naphtha is usually not effective as a solvent. Some materials being tested provide dispersant benefits without stabilizing the entire mass of the asphaltene. Solvent soak time, heat and agitation are important considerations for treatment.

#### 14-6.4. Mixed deposits

Combined deposits require a dual-solvent system, such as dispersion of a hydrocarbon solvent (usually aromatic) into an acid.

#### 14-6.5. Emulsions

Emulsions are stabilized by surface-active materials (surfactants) and by foreign or native fines. Generally, mutual solvents, with or without de-emulsifiers, are used for treating emulsion problems. De-emulsifiers, which may work well in a laboratory or in a separator or tank because of the large number of droplets in contact per unit volume, may not work by themselves in a porous medium because of mass-transport phenomena in getting the product to where it should work. Another reason they may not work alone is the mechanism involved in breaking emulsions, which should provoke the coalescence of droplets and then phase separation.

Asphaltic iron-catalyzed sludges are the most difficult emulsions to break. These emulsions are catalyzed by dissolved iron in the acid or water and resemble a crosslinked oil polymer in some instances. Prevention is the best treatment. An effective antisludge treatment for the area and an iron-reducing agent in the acid are the best methods. Removal of an existing asphaltene sludge is usually accomplished by dispersing it in a solvent and attacking the components of the sludge with additives designed for cleanup and removal.

#### 14-6.6. Bacteria

Prevention of polymer destruction by bacteria is usually handled with biocides and tank monitoring. Control of bacteria downhole is more difficult and involves scraping or treatments with sodium hypochlorite or other oxidizers followed by acidizing and then treatment with an effective biocide at a level at least 1.2 times the minimum kill level. Frequent rotation of the type of biocide is also necessary to prevent the development of biocide-resistant strains of bacteria.

#### 14-6.7. Induced particle plugging

- Mud solids

To remove shallow mud damage in natural fractures, a solvent or cleaner that will disperse the mud should be selected on the basis of tests of a field sample of the mud. Energizing the fluid with N<sub>2</sub> can assist in removing large masses of drilling mud from a fracture system. Experience with drilling mud cleanup from natural fracture systems shows that slugs of drilling mud may flow back on initial treatment, and damage can often reassert itself as mud moves from the outer reaches of the fracture system into the wellbore. This condition can require repeated treatments of the same high-efficiency cleaner, plus N<sub>2</sub>, to get good cleanup of the well. Acid may help, but tests of the acid's effect on the field mud sample are required.

When extremely large volumes of heavyweight mud are lost, it may be beneficial to sidetrack the well and redrill the pay zone. Whenever possible, the drilling mud overbalance should be minimized, and the mud should be conditioned to reduce solids before the pay zone is drilled. Experience with drilling highly fractured formations has led to experimentation with underbalance drilling in some zones. Underbalance drilling can result in only minimal damage in producing wells in comparison with the damage created by traditional drilling methods. There are dangers, however, in underbalance drilling, and the risk versus benefit must be evaluated carefully.

Mudcakes are usually damaging only in open-hole completions without significant fractures (Burton, 1995). In vertical wells, they are usually easily mechanically removed to a great extent by pressure drawdown. In long horizontal wellbores, the necessary drawdown is almost impossible to impose on any section other than the heel, particularly when a compressible fluid is in the hole. Circulations for mudcake removal should be conducted with minimum clearance between the wash pipe and the borehole to promote turbulence. Residual mudcake in prepacked screens or slotted liners completions is particularly problematic because it can plug the screen (Browne *et al.*, 1995; Ryan *et al.*, 1995).

- **Dirty fluids**

When particle damage is known to have occurred because of the use of unfiltered or poor-quality fluids, cleanup depends on finding a solvent or acid that can either remove the particles or break the structure of the bridges formed in the formation or fracture system. Surfactants, acids and mutual solvents are usually the most beneficial materials. The addition of  $N_2$  to provide a high-energy boost may also be beneficial.

The decision of which surfactant or mutual solvent to use should be based on core tests or field response. Including a gas such as  $N_2$  or  $CO_2$  is based on fluid and solids recovery requirements and wellbore unloading ability. For designing cleanup operations for particulate damage, flowing the well back quickly after the treatment helps in the removal of the particles. Lower pressure formations may require a gas boost. In higher pressure formations, natural flow is usually adequate to unload these solids, especially when a properly designed fluid has been used and the solids are no deeper than the surface of the wellbore face. Mechanical scraping and cleaning can exert influence only as far as the wellbore wall.

- **Acidizing**

The leading edge of an otherwise effective mutual solvent and acid system can be loaded with debris cleaned off the walls of the tanks and tubing. For this reason, the leading edge of the acid job is usually circulated out of the well using a process called pickling the tubing. In this treatment, acid and solvents are injected down the tubing to disperse and dissolve iron, pipe dope, mud and other debris from the tubing and are then circulated or reversed out of the well without being injected into the formation. These jobs are extremely effective when the tubing has not been cleaned or its condition is unknown. Volumes of both acids and additive treatments range from 1 to  $2\frac{1}{2}$  tubing volumes depending on the condition of the tubulars. Minimum acid and solvent volumes typically range from 250 to 500 gal. Coated tubing can reduce iron scale significantly, but other contaminants, such as scale and pipe dope, may still be present.

If load-fluid recovery influences well production, surfactants or mutual solvents that reduce surface and interfacial tension are usually benefi-

cial. The treatment volumes depend on the fluid, formation and amount of load fluid lost.

- **Waterfloods**

The removal of particles injected during waterflood operations depends on the identity of the material and use of a cleaner and an acid to disperse the material. One of the best techniques for cleaning up injection wells or disposal wells is to backflow the well as hard as possible prior to the treatment. This usually removes enough mass from the wellbore to eliminate the need for stimulation. However, if backflowing does not adequately clean the wellbore, acid and a mutual solvent in volumes ranging from 50 to 100 gal/ft are usually necessary. When large amounts of solids are expected, the well should be backflowed after acidizing. If oil carryover and emulsions are the problem, acid and a mutual solvent can be injected and displaced permanently with injection water behind the acidizing job.

#### 14-6.8. Oil-base drilling fluids

The prevention of OBM emulsions is relatively easy. Either a surfactant-base cleaner that is mixed after specific OBM testing or a more general xylene wash of the zone must be done before contact with either high-salinity brine or acid. After the cuttings and mud fines have been cleaned and totally water-wetted, the remaining damage problems of wettability can be reversed with a formation cleaner or mutual solvent. Acid is usually used as a following stage after cleaning to remove mud particles and clean up formation debris. Removal of known OBM emulsions resulting from mixing with high-salinity brine or acid usually requires an aromatic solvent wash or a specialized surfactant treatment that targets the silt-stabilized emulsion. Evaluation of any cleanup mechanism or treatment using laboratory samples of OBM should be avoided. Only field samples of the mud are appropriate for designing the removal treatment. Treatment fluid volumes range from 15 to 50 gal/ft of aromatic solvent or surfactant mixture, and the agitation and soak times are critical to the success of the treatment. Application difficulties include trapping the treating fluids across the pay in a column of heavyweight fluids where density segregation may be rapid. Packers and gelled plugs are the first line of isolation.

### 14-6.9. Water blocks

Removal of a water block can be accomplished using a surfactant or alcohol applied as a preflush to reduce surface tension, followed by a postflush of N<sub>2</sub> or CO<sub>2</sub> to remove the water from the near-wellbore area and reestablish gas saturation. Once the water has been mixed with the surface-tension-lowering materials, removal is easier. The difficulties in this type of operation are placement of the fluid and getting an even distribution of the fluid around the wellbore. Repeated treatments are usually necessary, and selective injection devices are beneficial.

### 14-6.10. Wettability alteration

Wettability alteration damage is removed by injecting (mutual) solvents to remove the oil-wetting hydrocarbon phase and then injecting strongly water-wetting surfactants. Again, a surfactant by itself will not work. The oil phase, which is usually precipitated asphaltenes or paraffins, must first be removed with a solvent. (The same applies to an adsorbed oleophilic surfactant.) Then, a strongly water-wetting surfactant can be injected and adsorbed onto the rock minerals. This reduces the tendency for new hydrocarbon precipitates to stick to the mineral surfaces and oil-wet them again.

For retrograde condensation problems, the most appropriate treatment technique is the injection of neat natural gas in a periodic “huff and puff” operation. Condensate is picked up by the gas and transported into the reservoir. Reprecipitation requires the retrograde of the process after several months of production.

### 14-6.11. Wellbore damage

- Mechanical damage from drilling

The drilling process itself modifies the local stresses around the wellbore, generating a zone of reduced permeability in the near-wellbore area (Dusseault and Gray, 1992). It has been shown that such damage affects primarily soft formations where the difference between the minimum and maximum stresses orthogonal to the wellbore is large. In the worst cases, the extent of the permeability decrease can be as large as 2½ wellbore diameters (Morales *et al.*, 1995), and perforations do not bypass the damaged zone. Because perme-

ability impairment in this case is the result of rock compaction, acidizing is ineffective. Short proppant fracturing treatments are apparently the only cure, though extreme overbalance perforating may give positive results in some cases (Petitjean *et al.*, 1995).

- Pipe problems

Whenever well production is reduced, the first determination should be to establish that the tubing is open and the lift system is working. Numerous pipe problems from leaks to collapsed pipe can occur, and fill in the tubing is also a possibility. Well conditions change over time, and an effective completion at the start of the well's life may not be effective after several years of production as the reservoir pressure declines.

- Poor perforations

The usual treatment for poor perforations is to add additional perforations. In zones that are extremely laminated, such as the shaly sands of the U.S. Gulf Coast and other areas, 8 to 12 spf is considered adequate, but perforation breakdowns (i.e., small fractures) may be required for complete linking. Lower perforation density is possible if the well will be fractured. Fracturing will cross the barriers of laminations, and in many field cases has provided extensive productivity increases.

Adding perforations is easy, but the typical 0° phased, small through-tubing guns deliver only small holes and short penetrations. The newer downhole-deployable guns that provide minimum clearance and phasing are preferred, especially when hydraulic fracturing will be performed.

- Hydrates

Hydrates are mixtures of ice and other elements, principally natural gas, that may resemble a dirty ice deposit. Unlike ice, they can form at temperatures greater than 32°F. The formation of hydrates is usually associated with a drop in temperature or a reduction in pressure that may accompany the production of fluids. Hydrates may also form in gas-cut drilling mud, particularly when the mud is circulated near the seafloor in cold locations. Hydrate plugging of chokes and valves can be a serious problem. Hydrate particle abrasion of equipment is also possible.

The most common occurrence of hydrates is in gas wells with a small amount of water produc-

tion. The quantity of water relative to the quantity of gas production is critical. As the water cut increases, many hydrate problems disappear. Hydrates are prevented by adding a freezing-point depressant such as alcohol or glycol below the hydrate formation point. They may also be controlled by temperature preservation in the produced fluid or the elimination of severe pressure drops that allow expanding gas to chill the liquids to their freezing points.

- Fill

Debris from formation spalling into the perforation or wellbore can be one of the most serious detriments to production. Fill in the wellbore is easily identified with a sinker bar on the wireline and is usually easily removed using tubing or coiled tubing and N<sub>2</sub> or foam unloading practices. Fill in the perforations is more difficult to identify and much more difficult to remove. When fill in the perforations is suspected, reperforating the well is generally the most direct method of testing the theory and restoring the well to productivity. Where the fill is acid soluble, acid injection may be useful; however, injecting acid into a perforation that is filled with small debris is usually difficult.

- Water problems

Water production is not only a major economic problem in surface separation, but it also causes a major reduction in the relative permeability of oil and gas. Water production from the well can lead to significant problems such as corrosion, back-pressure, emulsions and movement of the formation or fines. Water may flow from the bottom (coning), rise through fractures or flow from the edge in fractures through the matrix or in high-permeability streaks. Because of its low viscosity, water flows much easier than oil, and once in the

pores of the rock it is difficult to displace with low-viscosity fluids such as gas. Shutting off water (water control) is a special technique and is discussed elsewhere in the literature.

- Microporosity

Microporosity is created by a number of clays and a few minerals. It is simply a condition where a large surface area exists for water coating or trapping. Microporosity rarely presents a problem except when it occupies the pore throat area of the formation. In these cases, it may trap either debris or water and obstruct flow. The removal of microporosity can generally be accomplished with HF, or deep problems can be bypassed by fracturing.

## 14-7. Conclusions

To maximize well performance, the paths from the formation to the pipeline must present the lowest pressure impedance possible. Achieving this condition requires both a well-designed completion and the elimination of formation damage. The tools are an array of stimulation and damage removal techniques and chemicals that are readily available. Still, although formation damage removal seems easily achievable, the goal of a damage-free completion can be elusive. The problem is not so much one of finding a tool, but one of finding the right tool. A little experience shows that the right tool can be selected only when the problem has been identified. The effort and expense to understand the nature and identity of the problem can be the wisest investments.

The most common damage mechanisms and suggested methods of removal are listed in Tables 14-3, 14-4 and 14-5. It bears repeating that many damage conditions have similar symptoms and that there are no universal treatments.