
CHAPTER 8 **Special Topics**

Some readers may want additional information or more in depth discussion of the subjects mentioned throughout this guide. In this chapter, special topics that are of a critical nature are explored in more detail.

This chapter will cover:

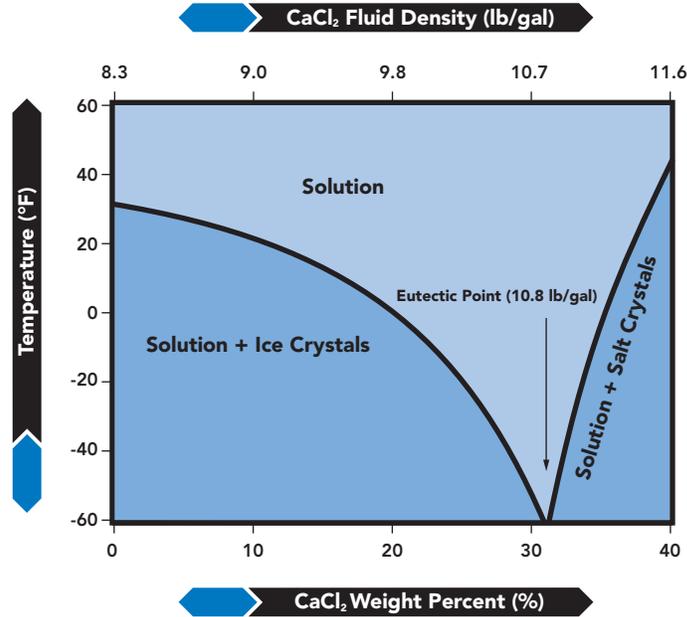
1. Crystallization Temperature
2. Corrosion Control
3. Displacement
4. Reduction of Fluid Loss
5. Filtration
6. Clarity

Crystallization Temperature

The crystallization temperature of a brine is the temperature at which a solid phase begins to form, resulting in a mixture of solid particles and solution. These solids may be salt crystals or water crystals (ice).

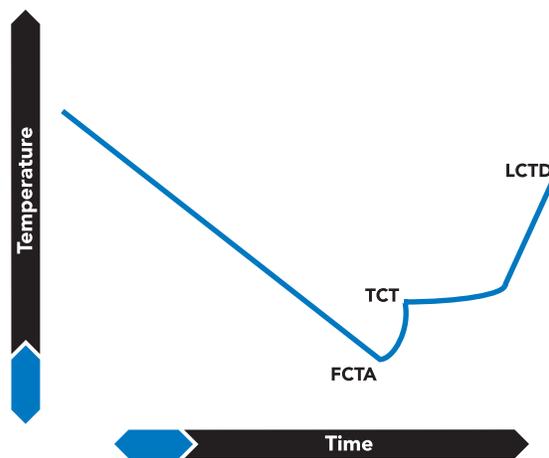
Figure 18 shows a typical crystallization temperature curve for a brine. The system plotted in Figure 18 is $\text{CaCl}_2 - \text{H}_2\text{O}$. Note that the left side of the curve slopes downward with increasing CaCl_2 concentration levels. This side of the curve is labeled *Solution + Ice Crystals*. It represents the freezing point of the brine, where ice crystals would begin to form. The right side of the curve is labeled *Solution + Salt Crystals*. It represents the phase boundary of the brine, below which salt crystals begin to form. The minimum point where the two curves intersect is known as the *eutectic point*. It is the point at which the minimum crystallization temperature can be realized. In essence, it is the lowest temperature at which a solid free solution (brine) can exist.

FIGURE 18. Crystallization Temperature — Aqueous Calcium Chloride



Virtually all single salt brines have similar phase diagrams. In oilfield applications, one is frequently operating on the right side of the eutectic point. Because of this situation, it is the crystallization temperature that should be the determining factor when selecting a clear brine fluid for a completion/workover application.

FIGURE 19. Typical Crystallization Curve



The crystallization point is determined by cooling a brine until salt crystals form, and recording temperatures at various times during the process. Figure 19 to the left shows a typical cooling curve for a brine. Note the three points along the curve. *First Crystal to Appear* (FCTA)

is the point at which salt crystals first form. The formation of salt crystals generates a small amount of heat, which causes a slight rise in the solu-

tion's temperature. This higher temperature corresponds to the *true crystallization temperature* (TCT) of the brine.

Once crystals have formed, the brine can then be heated until all the crystals are redissolved. The point on the curve which corresponds to the temperature at which the salt goes back into solution is labeled *Last Crystal to Dissolve* (LCTD). As a general rule, the TCT is the most commonly reported crystallization point. In practice, the TCT is extremely valuable since it is a strong reflection of the composition of the brine. It is, in fact, the most reliable and reproducible measure of the safe working limits of heavy brines. The measurement of TCT is governed by an API protocol.

In the case of multisalt brines, the least soluble component will crystallize at the TCT (Table 50). Thus, if a heavy brine is contaminated with minor amounts of NaCl or KCl from formation brine or seawater, the TCT may be shifted to a much higher temperature. This is due to the limited solubility of NaCl and KCl in heavy brines. Although the brine at the altered TCT may appear cloudy, it can be cooled to the original TCT with no further crystallization occurring.

TABLE 50. Least Soluble Component in Multiple Salt Brines

Multiple Salt Brines	Least Soluble Component
NaCl/CaCl ₂	NaCl
CaCl ₂ /CaBr ₂	CaCl ₂
CaBr ₂ /ZnBr ₂	CaBr ₂
CaCl ₂ /CaBr ₂ /ZnBr ₂	CaCl ₂

Formulation and Specification of Crystallization Temperature

Single salt brines have a unique composition and TCT for a given density fluid. Multisalt brines can be blended to a specific density several different ways, giving rise to a range of TCT formulations. During formulation and the specification of the crystallization temperature of a brine, a TCT should be chosen that is below the minimum expected average ambient temperature. In the case of deepwater applications, the mudline temperature will almost always be the minimum temperature for the entire circulating system. The use of FCTA or LCTD for fluid specification is discouraged. If FCTA is used as the specification, the TCT would be higher than the ambient temperature and would not provide adequate protection against crystallization. Using LCTD would result in a TCT well below average ambient temperature, which would result in the brine being more expensive than necessary.

The TCT of a brine is a critical use parameter for several reasons. First, if crystals form at the surface, the density of the resulting solution is lowered, which can result in pressure control problems. Second, if the TCT is not below ambient temperature, valves and lines can plug quickly, which can cause costly delays in operations. Third, getting the TCT right initially is important because adjusting the TCT at the well site is both costly and time consuming.

Pressurized Crystallization Temperature

TCT is a measure of crystallization temperature under atmospheric pressure. For most applications, the effect of pressure on solubility is slight. However, the effect of pressure can be significant under conditions involving a combination of high pressure and low temperature such as in deepwater applications at seabed or when pressure testing in colder climates. Under these conditions, some brines may crystallize at a temperature higher than the expected TCT, possibly varying by as much as 20°F. Therefore, the pressurized crystallization temperature (PCT) behavior of the brine should be known prior to usage. Unexpected crystallization could have disastrous results. At the mudline, where temperatures are lowest, choke or kill lines can plug and valves can seize, jeopardizing operations. Removal of crystals deposited during pressure testing in the BOP stack or in other locations where circulation is poor can be extremely difficult.

As a general rule, if the composition or density of the brine is represented by a point on the equilibrium curve to the right of the ice-salt eutectic, an increase in pressure will raise the TCT of the brine solution. Recall that salt precipitates at low temperatures for compositions or densities to the right of the ice-salt eutectic point (Figure 18). On the other hand, ice, rather than salt, precipitates for compositions represented by points to the left of the eutectic. A change in volume caused by elevated pressure can lead to a more concentrated solution from which salt will precipitate.

PCT Generalizations

Referring to the crystallization temperature versus weight percent curve in Figure 18:

- The TCT of brines at concentrations greater than the density corresponding to the minimum TCT (to the right of the eutectic point) will be raised by higher pressures in the well, i.e., $PCT > TCT$.
- The TCT of brines of lower concentrations than the eutectic will be lowered as more pressure is applied to the brine, i.e., $PCT < TCT$. In Figure 18, these low density brines are shown in the area to the left of the eutectic.

TETRA was the first service company to recognize the potential importance of PCT measurement and to develop the technology enabling such measurement.



If you are contemplating a deepwater or subsea completion, learn more about PCT by talking with your TETRA representative and have your fluid tested at TETRA's Technology Center to ensure the formulation of your brine has been adjusted for the effects of PCT.

Corrosion Control

Corrosion Overview

Corrosion involves the loss of metal, usually iron, to its environment. If conditions are nonoxidizing, this dissolved iron may remain in solution in the form of ferrous iron, imparting a green tint to the CBF. However, if conditions are oxidizing, the dissolved iron may further oxidize to the ferric ion, which will commonly form reddish brown ferric hydroxide and cause formation damage.

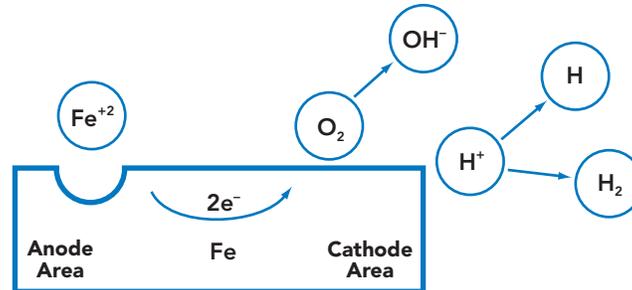
In the corrosion process, the metal loses electrons and some other species—such as an oxygen molecule or a hydrogen ion—accepts them. The site where the loss of electrons takes place is called the *anode*. The site where the electrons are accepted is called the *cathode*. These sites are often at different locations on the metal with the electrons being shunted through the metal as shown in Figure 20.

For electron migration to occur, two other aspects are needed: (1) a conductive phase, in this case the metal and (2) an electrolyte, which acts as a medium for the electrolytic reactions and facilitates the removal of the corrosion products from the corroding surface.

For corrosion to take place, these four components of the corrosion system must coexist:

1. an anode—a susceptible area on the metal surface,
2. a cathode—oxygen or other electron acceptor,
3. a conductive path—the body of the tubing or casing, and
4. an electrolyte—field brine or CBF.

FIGURE 20. The Corrosion Process

**Anode:**

Solubilization of Fe as Fe⁺²

Cathode:

Electron (e⁻) migrates to acceptor (O₂), reacting to give hydroxide ion (OH⁻), or

Electron (e⁻) migrates to acceptor (H⁺), reacting to give hydrogen (H or H₂)

An important facet of inhibiting or minimizing corrosion is controlling the electrode processes—the phenomena occurring at the anode and cathode. If these processes can be interrupted in some manner, the corrosion rate will be dramatically reduced. Since the anode and cathode reactions depend on one another, any means which hinders either reaction will also hinder the corrosion. Removing or reducing the effective concentrations of one or more of the reactants will accomplish this.

One can decrease corrosion by covering the surface of the metal with a physical barrier such as a chemical coating or by reducing the reactivity of the iron by what is called passivation.

Inhibiting the cathodic reaction is accomplished by reducing the concentrations of corrosion accelerators such as oxygen molecules, hydrogen ions, and other metallic ions.

The cathodic reaction can be interrupted by:

1. keeping oxygen out of the system,
2. reducing the concentration of hydrogen ions by increasing the system pH, and
3. removing accelerators like ferric ions.

Oxygen Control

The addition of one of TETRA's oxygen scavengers, like OxBan or OxBan HB, can reduce corrosion dramatically by limiting the reaction of oxygen at the cathode—less oxygen, less reaction. With respect to corrosion control, oxygen can be entrained in brine fluids and pumped as small

bubbles (or foam) during recirculation and filtration procedures. Therefore, generation of foam during these operations should be minimized. Additionally, small amounts of an oxygen scavenger can be added continuously just before the fluid goes downhole. More effective corrosion inhibition is achieved by employing a combination of one of the oxygen scavengers and a corrosion inhibitor like TETRAHib or TETRAHib Plus.

If the fluid is not under pressure, oxygen solubility in brines is reduced with an increase in temperature. However, with applied pressure, oxygen cannot escape from the fluid as the temperature rises.

Oxygen control is extremely important in minimizing environmentally assisted cracking. Consequently, the scavenger and treatment level must be chosen carefully. For more information, see "Environmentally Assisted Cracking" on page 189.



OxBan should not be used with calcium or zinc containing brine fluids and should be avoided with CRAs. OxBan HB is an excellent alternative that avoids potential precipitation and acidity issues.

Hydrogen Ion Reduction

The hydrogen ion is a corrosion accelerator, and the concentration of hydrogen ions can be controlled during the manufacturing process. All TETRA clear brine fluids are carefully monitored to control pH during manufacturing.

Other Contributors to a Corrosive Environment

- High Pressure/High Temperature
- Scale (e.g., CaCO_3 , CaSO_4 , FeS, ZnS)
- Sulfur Producing Species/Bacteria (e.g., H_2S sources)
- Metallurgy
- Stress
- Mechanical Deformations/Crevices

Major Types of Corrosion

Corrosion is a complex subject involving a broad spectrum of materials, chemistries, and practices. A brief discussion of some of the more pertinent types of corrosion follows. Two major types of corrosion are general (or uniform) corrosion and localized corrosion. These are discussed in the following sections.

General Corrosion

Uniform or general corrosion is corrosion that is uniformly or widely distributed across the surface of the metal. With the loss of metal occurring across a large (if not the entire) surface of the metal, uniform corrosion rates are much higher than local corrosion rates. Perhaps the most serious general corrosion type, since it is often not anticipated, is *galvanic corrosion*, which occurs due to the interfacing of two different metals. The potential or galvanic difference between the two metals—the ease with which they give up electrons—induces a cathodic/anodic reaction between the two metals.

Localized Corrosion

Localized corrosion is corrosion that is confined to small, specific sites on the surface of the metal. This type, although limited to a small region, can be especially insidious. Localized corrosion can proceed inward from the surface of the metal. In extreme cases, it can ultimately lead to cracking or failure of the metal. Localized corrosion, which leads to small dot-like regions or cavities on the surface of the metal, is called *pitting*. Pitting may have serious consequences, since corrosion may easily continue deeper into the metal, owing to the development of a concentration cell.

More specific types of localized corrosion are described in detail below, including:

- Concentration Cell Corrosion (crevice, etc.)
- Hydrogen Embrittlement (hydrogen induced cracking)
- Environmentally Assisted Cracking

Concentration Cell Corrosion

Concentration cell corrosion results from differences in electrical potential that develop due to differences in the concentration of dissolved ions in CBFs. This is perhaps the most common type of corrosion because, invariably, small concentration differences exist in different locations throughout the fluid due to factors like temperature variations and mixing limitations. Crevice corrosion is a specific type of concentration cell corrosion that results from different concentrations of species inside and outside the crevice. The key species are often oxygen or hydrogen, but they can also be nonreactive ions. Corrosion due to concentration differences can be severe in the bottom of a pit or cavity.

Hydrogen Embrittlement—Hydrogen Induced Cracking

Hydrogen induced cracking (HIC) results from the migration of hydrogen atoms from the metal surface into the metal lattice, followed by the

recombination of hydrogen atoms to form hydrogen gas. The gas either causes blistering on the metal surface or induces cracking along weak matrix elements, such as inclusions or grain boundaries. The probability of induced cracking can be enhanced by stress, leading to a stacking of cracks, transgranular cracking, and possible tubing failure. Reduced acidity and reduced sulfur content decreases the metal's susceptibility to hydrogen induced cracking.

Environmentally Assisted Cracking

The term, *environmentally assisted cracking* (EAC), encompasses all of the forms of stress corrosion, whether such corrosion is induced by hydrogen embrittlement, chlorides, other halides, or sulfides. To initiate EAC, three essential conditions must be present: (1) stress in the tubing, (2) a sensitive metallurgy, and (3) a corrosive environment. Minimizing the potential for catastrophic failure in today's HPHT wells is a difficult challenge, because all three conditions necessary to initiate EAC are often present in such wells.

It should be noted that the tensile stress needed to induce cracking and potential tubing failure can be substantially below the metal's indicated tensile strength. Moreover, the stresses that may contribute to a cracking event can come from either the external forces acting on the pipe, such as the mechanical stresses generated as a result of its service in the well, or from internal stresses residual from any of the metal's manufacturing processes, such as cold working, drawing, rolling, or annealing. Cracking is not normally accompanied by general corrosion of the tubing's surfaces; instead, it often emanates from deep invasive pitting. In some cases, the propagation of cracking can be extremely rapid with catastrophic failure occurring in as little as a few days. However, catastrophic failure can also take months or even years to occur.

The use of corrosion resistant alloys has markedly increased with the growth in drilling HPHT wells. Where general corrosion was the concern with carbon steel tubing, environmentally assisted cracking has become the blight of the stainless steels. The austenitic 300-series stainless alloys, such as 304 SS and 316L SS, are particularly susceptible to EAC. Even the normally greater corrosion resistant martensitic 13 chrome and duplex (ferritic/martensitic) chrome alloys have experienced failure when stressed in company with certain corrosive fluids. The threat of EAC has become a significant problem since most of the CRA materials in use today are martensitic 13 chrome alloys of various composition.

Many of the tubing failures in the last five to 10 years have been attributed to stress cracking or EAC that has been induced by the corrosive environment in the annulus (from the back or packer fluid side). This type of cracking can more precisely be termed *annular environmentally*

assisted cracking (AEAC) to distinguish it from the EAC that is induced by the production fluids on the inside of the tubing.

EAC or AEAC events are usually categorized as being either of two types: (1) stress corrosion cracking (SCC) or (2) sulfide stress cracking (SSC). By examining crack patterns and debris deposited in cracks, metallurgists can often identify the cracking type. In some cases, however, the cracking mechanism appears to involve a blend of the two. Overviews of these two types are provided in the following section:

Stress Corrosion Cracking. Stress corrosion cracking (SCC), often referred to as halide or chloride stress cracking, depends upon a variety of factors such as the metallurgy; the pH; concentration levels of CO₂, oxygen, and sulfur; the temperature; the halide (chloride or bromide) content; and applied or residual stresses. As a general rule, the susceptibility for this type of cracking increases with higher oxygen content, increased halide concentration, and elevated temperature. In view of the complexity of the interaction of these factors, TETRA does not specify general halide concentration maximums, but takes a total system approach to minimizing this type of corrosion.

With respect to pH, the presence of high concentrations of chloride or bromide ions can locally enhance the acid concentration by reaction of the halide ions with metal ions in crevices or under scale. Such concentration effects can then initiate concentration cell corrosion and pitting—the latter often being the genesis of cracking. For additional discussion of the effect of the halide ion, see “Salinity Concentration” in the “Key Corrosion Factors” section, beginning on page 191.

Sulfide Stress Cracking. Sulfide stress cracking (SSC) results from the presence of hydrogen sulfide (H₂S) in the fluid environment. This toxic gas elevates the acidity of the fluid, increasing its corrosivity. It also supplies a sulfide ion that can either be readily oxidized to elemental sulfur or can react with various heavy metals to precipitate metal sulfide scale. The insolubility of the sulfides and elemental sulfur can lead to localized corrosion or concentration cell corrosion with high acid concentrations being trapped under the solid deposits. Sulfur is invariably found in association with high concentrations of hydrogen sulfide. Moreover, hydrogen sulfide has been found to react with elemental sulfur to form a particularly corrosive species.

SSC is a specialized form of hydrogen induced cracking or embrittlement. The presence of H₂S promotes the movement of hydrogen atoms from the metal's surface into the metal's matrix. This induces the hydrogen atoms to form hydrogen gas (H₂) at points of stress in the metal, for instance, at the grain boundary or at an inclusion in the metal's matrix,

which can then lead to cracking. The hydrogen embrittlement component is more prominent in the carbon and low alloy steels than in the martensitic CRA steels. As a general rule with low alloy steels, reducing the acidity will inhibit SSC. High temperatures will also lower the chance for SSC. Maximum susceptibility for SSC in martensitic stainless steels occurs at approximately 68°F.

Fluid/Metal Compatibility Testing—MatchWell Fluid Compatibility Selector

Because the use of CRA tubular materials is a relatively new practice, there is little empirical data to draw upon when making completion decisions. Most of the conventional wisdom on the matter comes from the extrapolation of data from conventional completions, miscellaneous observations of failures, and a minimum of test data. In an effort to better serve our customers, TETRA has participated in extensive testing to learn more about AEAC and how to reduce its probability.

In this research effort, TETRA has conducted comprehensive matrix testing under a variety of downhole conditions: e.g., select chrome tubing under high stresses, temperatures up to 400°F, typical completion and packer fluids across the full density range from 9.0 lb/gal to 19.2 lb/gal. The testing also examined the impact contamination from corrosive gases and other materials would have. Using the test findings, TETRA created the MatchWell fluid compatibility selector, which can be used to match any tested CRA tubing metallurgies with TETRA CBFs. This computer program provides cracking susceptibilities indices (CSIs) for various metallurgy and fluid combinations. The MatchWell program allows TETRA to provide operators with the information and opportunity to select tubing and fluids that have been tested and matched for optimal performance and cost effectiveness.

Key Corrosion Factors

With respect to AEAC, careful attention must also be given to several properties of the CBFs. Four factors are of primary importance: (1) the salinity concentration, (2) the oxygen content, (3) the pH, and (4) the presence of CO₂, H₂S, or sulfide levels.

Salinity Concentration. The salinity, or halide concentration, is significant to the potential for AEAC, particularly stress corrosion cracking, in that it is implicated in the formation of localized corrosion (pitting). As this corrosive process proceeds, due to the presence of halides, very low pH can be developed within the pit, leading to more severe pitting and possibly to cracking of the metal. Although there have been attempts to assign definitively safe halide concentrations for corrosion resistance,

this practice is best avoided, since TETRA's test findings point to the importance of other minor variables such as contaminants, metallurgical variations, and other unexpected factors as contributive to SCC.

Chlorides, and not bromides, are frequently implicated in SCC events. However, our testing indicates that, in certain conditions, bromide fluids can exhibit SCC, while fluids containing chlorides can perform exceptionally well.

For a given metallurgy and stress level, the halide ion concentration that becomes pernicious with respect to stress cracking depends on temperature and the concentration of CO_2 and/or H_2S . At temperatures of $\sim 200^\circ\text{F}$ and greater, the potential for cracking becomes highly dependent on the halide concentration. Regardless of the halide concentration, increased hydrogen sulfide and/or CO_2 intensifies the potential for cracking.

Oxygen Content. There is no indicated minimum limit for oxygen content that will ensure that there is no risk of AEAC. Cracking has been reported in fluids with less than 0.5 ppm oxygen; however, our extensive testing suggests the detrimental influence of other substances in these failures. This conclusion stems from the fact that, in a number of our tests, high levels of oxygen were present but no failures occurred. In general, many studies have concluded that minimizing oxygen content in the fluid is advisable. The combination of oxygen with H_2S , or more significantly the S^{2-} (or HS^{-1}) ion found in neutral to alkaline H_2S solutions, is especially dangerous with respect to AEAC.

Due to the potential for pitting and severe localized corrosion, strict oxygen control by the application of oxygen scavengers should be viewed as imperative to AEAC inhibition. As a general rule, it is always advisable to ensure that oxygen scavenger levels are optimized during final circulation prior to setting the packer.

pH. At low pH ($\text{pH} < 7$), the hydrogen ion (H^+) can be converted at cathodic sites to atomic or molecular hydrogen and, coupled with stress, can lead to HIC. Additionally, at low pH, highly localized, strongly acidic sites can develop and lead to pitting. As a consequence, the pH of the brines should be kept alkaline ($\text{pH} > 7$), if possible, to prevent these occurrences.

CO_2 , H_2S , or Sulfide Level. It is important to minimize the H_2S or sulfide level to avoid the formation of sulfur and related species at pitted sites. The use of sulfide scavengers or biocides to inhibit sulfate reduction can be enormously helpful. Similarly, an increase in CO_2 concentration also

heightens the potential for cracking. The most likely influence of the CO_2 is its propensity to lower the pH of the fluid environment.

Metallurgical Issues

Acting on generalizations about metallurgies that will resist AEAC can be dangerous. Our testing program has identified a number of combinations of chrome tubing and CBFs that are compatible in the harshest of downhole conditions. Higher chrome or other exotic alloyed materials are often selected for use with the hope that these will be impervious to the assault of halide ions and other corrosive substances. Testing, however, has shown that this practice does not always result in the best technical solution; it also can be very expensive.

Even at high temperatures and in the presence of known corrosion enhancers like H_2S and oxygen, lower order CRAs and chloride fluids can perform as well as exotic alloys and bromide fluids. In many cases, small concentrations of contaminants, formerly considered insignificant, contribute to AEAC. Often, it is a combination of two or more factors working synergistically to the metal's demise. TETRA's comprehensive matrix testing has identified many significant factors that can provide guidance when making completion decisions and selecting materials.

Displacement

The term, *displacement*, as it pertains to the transition from drilling to completion operations, has come to encompass the entire process of removing the solid laden drilling fluid and replacing it with a solid free completion fluid. In reality, there are three separate processes involved in a successful displacement:

1. removal of the bulk of the drilling fluid from the wellbore,
2. wellbore cleanup during which the remainder of the drilling fluid residue is removed, and
3. installation of the solid free completion fluid.

An efficient displacement completely removes the mud from the wellbore, maintains the integrity of both the brine and the mud, establishes a solid free environment, and minimizes filtration time. All of these criteria must be met in the most cost efficient manner.



It is imperative that incompatible fluids always be separated.

Heavy brines are incompatible with water based and oil based muds. This incompatibility can produce a viscous, un-pumpable mass due to flocculation of the mud by high salt content of the brines. Should this reaction take place downhole during the displacement, the friction pressures will increase dramatically. As additional commingling takes place, a point may be reached where pumping operations have to be suspended due to excessive downhole casing, tubing, or pump pressures. The contamination of completion fluids by solid laden drilling fluids can result in the inability to process the fluid through filtration equipment, making it impossible to maintain the required solid free environment.

Displacement Methods

Generally, there are two techniques available to achieve a successful displacement. These methods are referred to as *indirect displacement* and *direct displacement*.

Indirect Displacement. The indirect displacement method displaces the mud using water. Seawater is circulated downhole one time and is discarded upon its return to the surface. This rinsing process continues until drilling mud residue in the returns is minimal. At this point, one or more chemical sweeps are circulated through the hole. These sweeps are designed to dislodge any drilling mud that remains on the surfaces of the wellbore. Once this residue has been dislodged from the surfaces, viscous fluid is circulated through the wellbore to aid in its removal from the well. Indirect displacements yield good results at low cost. However, several factors can limit their application, including:

- an inadequate supply of available water,
- an inability to discharge water due to environmental regulations (zero discharge),
- discharge volume limitations,
- environmental contaminant levels,
- pressure and integrity considerations, and
- rig time cost.

Direct Displacement. A direct displacement differs from an indirect displacement in that it accomplishes all three displacement processes in one circulation or sequence. In effect, you are able to go directly from the drilling fluid, into the cleanup system, and then into the completion fluid without the interruption of a rinsing process, which can be time consuming. Some of the benefits of a direct displacement are: minimizing rig time spent in pumping, reducing generated waste, and maintaining required wellbore pressures.

There are five major points to consider prior to conducting direct displacement operations:

1. chemical displacement system design,
2. condition of surface equipment,
3. pre-displacement condition of mud,
4. condition of flow path, and
5. pressure differentials.

Chemical Displacement Systems

TETRA's highly engineered chemical displacement systems are designed to disperse solids and water wet all metal surfaces. Components of the system can be designed for indirect or direct displacement of water based, diesel oil based, and synthetic oil based muds.

TDSP Displacement System

The TDSP spacer system requires the pumping of a minimum of three spacers. Each spacer is specifically designed by your TETRA fluids specialist to perform one of the three displacement processes and maintain compatibility with the fluids it contacts.

TETRA developed this multistage system to separate the drilling fluid from the brine. The system consists of the TDSP I weighted spacer, the TDSP II surfactant wash, and the TDSP III viscosified sweep. The overriding design consideration for this system is to maintain compatibility of all fluids which contact each other.

TDSP I. The mud displacement stage, TDSP I is a weighted spacer designed to act as a piston within the wellbore to push the drilling fluid ahead of it. A TDSP I weighted spacer relies on yield point, gel strength, density, and apparent viscosity to maintain its integrity as it travels through the wellbore. By acting as a piston, the TDSP I pill effectively prevents the channeling of fluids.

TDSP II. The surfactant wash stage, TDSP II is a turbulent flow spacer with concentrated surfactants that is specifically designed for the mud type. This stage works to disperse any residual mud from the tubular surfaces. The TDSP II spacer is designed to provide a minimum of 2,000 feet of coverage and a minimum of 10 minutes contact time in the largest annular section of the wellbore. While maximum pumping rates are often limited by pump capabilities, an annular velocity of 180 ft/min is recommended in each annular interval.

Another essential design factor in the TDSP II spacer is to ensure that sufficient TDSP II is available to incorporate the entire volume of anticipated

drilling mud residue that may be present. In some cases, this consideration overrides the annular coverage and contact time recommendations mentioned above. This consideration requires extensive testing of the TDSP II spacer for its maximum residue capacity. It is always desirable to perform these tests on a sample of the mud from the wellbore for which you are planning the displacement.

TDSP III. The viscosified sweep stage, TDSP III is the spacer used between the surfactant wash spacer and the CBF. This stage is designed to remove any residual materials that are dispersed by the surfactant wash and to provide warning of the returning brine. This warning allows time for personnel to divert returns once the spacer system has been circulated out of the well. Like TDSP I, TDSP III should exhibit rheological properties that allow it to maintain its integrity while traveling through the wellbore. This integrity is essential in minimizing the commingling of the TDSP III and the CBF. Individual stage volumes shown in Table 51 are designed with three goals in mind:

1. to allow physical separation to protect brine from mud contamination,
2. to provide sufficient contact time for efficient cleaning of the wellbore, and
3. to carry residual solids out of the wellbore.

TABLE 51. TDSP Displacement System

Guidelines for Individual Spacer Stage Annular Coverage		
Stage	Feet ¹	Contact Time (min)
TDSP I	1,000	5
TDSP II	2,000	>10
TDSP III	1,000	5

¹Recommended feet of coverage in largest annular volume in well

TETRAClean Displacement System

Environmental regulations in some oil and gas provinces, such as the North Sea, may suggest the TETRAClean™ displacement system. This alternative product has found wide acceptance because:

1. it is a one pill-one pit system that conserves scarce pit capacity on offshore platforms,
2. it consists of components that have earned a *Gold* designation in accordance with Chemical Hazard Assessment and Risk Management (CHARM) regulations promulgated by the OSPAR Commission for the Protection of the Marine Environment of the North-East Atlantic, and
3. the recommended higher annular velocity used in TETRAClean displacements results in a much shorter displacement time.

One Pill–One Pit. As pit volume is a scarce commodity on any offshore platform, the TETRAClean displacement system was designed around the concept of one pill-one pit. The TETRAClean displacement pill is typically made up in the range of 200 to 250 bbl. In actual practice, the volume is designed around achieving a contact time of 10 minutes. For maximum benefits, a minimum annular velocity of 250 ft/min is recommended (if practicable) to promote the scouring and suspending action associated with highly turbulent flow. This higher annular velocity has the added benefit of shortening the time of displacement operations.

In monovalent brines, such as those based on sodium or potassium salts, the TETRAClean pill is mixed in a volume of working brine that has been viscosified with TETRA BioPol viscosifier. A yield point of more than 50 lb/100ft² is recommended for the viscosified pill. The two active components are TETRAClean 105 surfactant and TETRAClean 106 activator.

In calcium based fluids, TETRAVis L HEC viscosifier is the preferred viscosifying agent. In those cases, TETRAClean 105 surfactant is used alone, but at a higher dosage rate because of the chelating tendency of TETRAClean 106 activator toward divalent ions.

Environmentally Friendly. Offshore oil and gas activities in the North Sea are guided by stringent environmental regulations. Under the internationally recognized OSPAR Commission, all chemicals used must comply with standards set under the CHARM program. TETRAClean 105 surfactant has earned a *Gold* designation under this classification system. TETRAClean 106 activator has been shown to “*present little or no risk*” (PLONOR) of environmental damage.

General Applications. The TETRAClean one pill displacement system can be run after water based, diesel oil based, or synthetic oil based drilling fluids, provided a compatible spacer is run between the mud and the TETRAClean pill. Recommended practice for the TETRAClean pill involves

circulating down the working string. Wells with large or abrupt changes in diameter may require special attention to ensure that mud residue is not left on the shoulder of the liner top. Additional cleaning action may be accomplished with a bypass circulating tool (e.g., TETRA's Selective Rotation Circulating Tool) to ensure there is adequate fluid circulation at the liner top.

The principles of good displacement outlined in the following sections are equally important when using either of TETRA's chemical displacement systems.

Displacement Modeling Software

When planning displacement operations for our customers, TETRA uses modeling software to determine product applications and whether high pressure pumping equipment may be required. The software programs and their uses are explained below.

CV-Pro™ circulating volume and displacement modeling software is used to calculate well volumes and displacement data (i.e., spacer volumes, spacer coverage, and spacer contact time as a function of pump rate), which are values used in well displacements. The program also calculates surface area, individual well capacity, and annular velocities. The CV-Pro program is also useful in providing information necessary for spotting balanced plugs or pills. Additionally, the program is a useful tool when planning the minimum pill volume and the necessary pump rate for optimal displacement spacer performance.

DIS-Pro™ hydraulic modeling software is used to model a specific displacement operation and provide detailed information on anticipated pump pressures, hydraulic horsepower requirements, equivalent circulating densities, and other pressure calculations in a displacement timeline format. The program is designed to simulate all configurations of the wellbore, as well as forward and reverse fluid circulation options, bypass flow (downhole bypass circulating valves), and two stage open-hole displacements at all given pump rates. The DIS-Pro program can also calculate a backpressure schedule to maintain a constant bottom-hole pressure when necessary. The program will also identify freefall events and calculate downhole pressure losses. A DIS-Pro simulation is recommended to optimize and define appropriate displacement operation parameters.

Condition of Surface Equipment

Prior to the arrival of the brine at the rig site, personnel should be directed to check the cleanliness of the fluid handling tanks, flowlines, pump suction, manifolds, and gun lines. There should be no visible

water, dirt, rust, or scale deposits. Pressure washers and surfactants should be employed to thoroughly clean all surfaces. The surfactant used should be chosen on the basis of being the most effective for the particular drilling mud involved.

It is also important to check for possible leaks at hose connections, dump valves, tank inspection plates, pumps, flowlines, and bell nipples. Some completion fluids are considered marine pollutants and must not be released into the environment. In these cases, all dump valves should be closed. Secondary sealing methods (for example, applying silicone sealer or welding the valves) are recommended. Valve handles should be locked out and tagged out to prevent inadvertent opening.

All active pits should be covered. Fully enclosed tanks are essential for spike fluid storage due to the hygroscopic nature of high density brines. Sources of water, such as hoses, drains, sinks, and water addition lines, should also be locked out and tagged out. Other sources, such as eye wash stations, should be checked regularly for leaks, and repairs should be made as they become necessary.

The condition of surface equipment must be given serious consideration. In many cases, the completion fluid system represents a substantial investment. Any preventative action which costs less than the value of the fluid system or the cost to remove contamination is always justified.

Predisplacement Condition of Mud

Prior to displacement operations, the drilling fluid should be circulated a minimum of one annular volume (bottoms up) and the properties checked. Regardless of the mud type, good rheological properties are of the utmost importance. In addition to optimum mud properties, recent movement of the mud is essential.

Oil based muds generally maintain good rheological properties and seldom present any problems. A good mud check after circulating one annular volume (bottoms up) is still recommended to verify acceptable rheological properties.

Condition of Flowpath

Mud mobility is essential to a successful displacement. Obviously, the first thing to do is to obtain circulation to the required depth. If the mud is in good condition, it may only be necessary to circulate several hole cycles to distribute the solids. In less than ideal circumstances, it may be necessary to wash through or even drill out settled solids. If at all possible, the mud should be circulated until the displacement begins. Cleaning rig pits prior to introducing completion fluids into them may take

many hours. During this time, even the best muds may develop high gel strengths or barite settling may occur in the wellbore.

The most effective and least expensive method of removing mud solids from tubular goods is to use TETRA's specially designed scraper and brush tools. While going in the hole, these tools physically disrupt the filter cake that forms in the wellbore. This mechanical removal eases the burden on the TDSP II surfactant sweep. After the completion fluid has been circulated into the wellbore, it is advisable to short trip (re-scrape) the wellbore to remove any residual mud materials. This step should then be followed by circulation and filtration of the completion fluid.

Pressure Differentials

DIS-Pro hydraulic modeling software can be used by fluids specialists to analyze displacement hydraulics so that pressure differentials can be minimized through proper adjustment of individual spacer densities and/or rheology. Minimizing excessive pressure differentials is important, as they can interrupt pumping due to elevated pump pressures or tubular strength limitations.

Another point regarding pressure differentials relates to displacing a light fluid with a heavier fluid. As the fluid enters the wellbore, the heavier fluid may force the lighter fluid from the hole more rapidly than good judgment would dictate. This *u-tube* effect should be controlled by maintaining back pressure with the choke. If this is not done, interfacial losses tend to be high due to poor fluid hydraulics. This situation often results in density loss as well. Fluid economics aside, safety is compromised any time the wellbore is not under control.

Factors Influencing Displacement Efficiency

Rheology

The rheology of the mud and the spacer system is a major factor affecting displacement efficiency. Consider the behavior of a fluid flowing through a pipe. If the velocity of the fluid is very low, individual particles of fluid tend to move in straight lines parallel to the direction of flow. The flowing fluid consists of very thin, cylindrical layers of fluid concentric with the tubing walls. These layers, or lamina, give rise to the term *laminar flow*.

The particles of fluid in an individual layer move at the same velocity. However, the different layers will ordinarily move at different velocities. Theoretically, the layer next to the wall is stationary, layers close to the wall move slowly, while those close to the center move more rapidly. If

you think of the layers as sliding by one another, the relative velocity between two adjacent layers is known as the *shear rate*.

Fluid tends to resist having its individual layers move at different speeds. The resistive force that a layer offers to prevent nearby layers from sliding by is called the *shear stress*. At higher velocities, fluid is not ordinarily in laminar flow. Instead, individual particles tend to bounce and tumble along in an almost random way. This type of flow is called *turbulent flow*.

When very low velocities are combined with relatively high viscosities, a situation occurs whereby the fluid flow almost resembles a solid. Particles tend to remain relatively stationary with respect to one another, and the fluid travels down the tubing as an almost solid mass. This occurrence is called *plug flow*.



The removal of solids from casing walls by scrubbing action is best accomplished by highly turbulent flow. High velocity is characterized by high turbulence and good scrubbing action. A velocity of 180 ft/min in the largest annular section of pipe is recommended.

In order for the various spacers in the TDSP system to work properly, it is imperative that the drilling fluid rheology be controlled. In simplistic terms, the yield point is a measure of the ability of a fluid to hold together under applied stress. Ideally, we reduce the yield point of the mud to the bare minimum that is required to support barite. If the yield point of the mud removal spacer is less than the yield point of the mud, then the spacer will channel through the mud and hole cleaning capability will be severely reduced.

Direction of Circulation

Another major factor affecting displacement efficiency is the direction or type of circulation employed. The densities of the brine and the fluid being displaced influence the flow path to be used. The lighter fluid should be above the heavier fluid in the annulus. Under static conditions, high density fluids tend to sink through low density fluids due to the effect of gravity. Because of this, even with spacers to separate incompatible fluids, intermingling and flocculation is possible.

Reverse circulation offers several advantages over standard circulation when conditions permit. The direction of the flow path is a primary factor in determining individual stage volumes. When reversing, higher fluid velocities in the tubing prevent solids from slipping back down the

wellbore by maximizing the lifting capacity of the fluid. Therefore, less physical separation is required.



Whenever possible, the lead spacer should be 0.5 lb/gal to 1.0 lb/gal heavier than the mud being displaced.

Wellbore Eccentricity

Wellbore eccentricity occurs when the working string passes through a section of cased hole that deviates from the vertical axis. Virtually all wellbores have some deviation; some of this deviation is intentional and some is not. The number of deviations and the severity of the individual deviations will greatly affect the displacement.

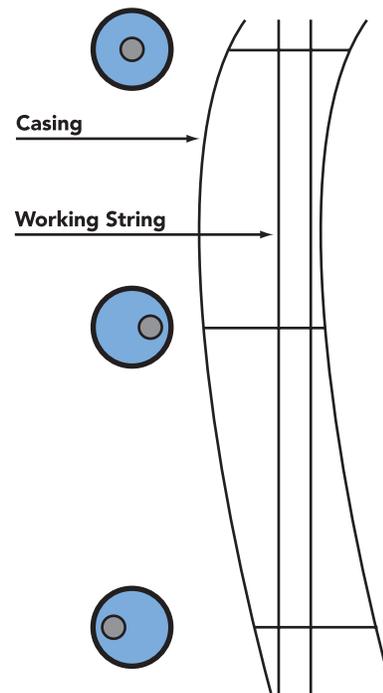
If a typical vertical wellbore profile is examined, where no individual deviation angle is greater than 3° , it is apparent that even with the small amount of vertical deviation, hundreds of feet of working string are in contact with the casing. The casing/working string interface causes static mud stringers that are extremely difficult to remove.

The degree of eccentricity in the annulus is defined by the term *percent standoff*. When the working string is perfectly centered in the wellbore, the percent standoff is 100%. If a working string creates an annulus with a one inch gap when centered and is then set off 0.5 inches from the casing wall, the resulting annulus has a 50% standoff. Percent standoff decreases as the eccentricity in the annulus increases. Percent standoff and displacement efficiency are directly related. As percent standoff decreases from 100% with all other parameters kept constant, the displacement efficiency decreases and larger spacers are required.

Pipe Movement

The ideal situation would be to centralize the working string, but this is not typically done in practice. Rotation of the working string is an effec-

FIGURE 21. Wellbore Eccentricity



tive alternative. By rotating slowly during the displacement, mud channels can be broken up and removed efficiently.

It is not uncommon to be unable to rotate the pipe when rigged up for reverse circulation. Reverse circulation requires either the Hydril® or pipe rams to be closed, and many operators are unwilling to subject the Hydril to any extra wear.

If the well design will allow setting 4,000 to 5,000 lb of weight on the bit, an alternative to pipe rotation is to pick up and slack off string weight. This action causes pipe movement, which aids in the removal of mud stringers.

Exaggerated pipe reciprocation should be avoided while introducing the brine. In addition to pressure fluctuations, there is a tendency for interface sizes to increase due to increased movement in the annulus. Reciprocation can be beneficial during predisplacement mud conditioning or while circulating seawater in the well. The physical motion of the pipe helps remove solids that are adhering to the tubular surfaces.



It is important to remember that the pumps must not be shut down during the displacement operation. If the pumps are prematurely stopped, the displacement system may string out and cause a decrease in hole cleaning effectiveness. This could possibly lead to contamination of the brine with particulate solids.

When weighted spacer systems are designed to incorporate all down-hole conditions and are engineered with all available technologies, overall well costs can be reduced. This reduction will be seen in reduced filtration requirements, reduced rig time associated with filtration, and in the reclamation of contaminated fluids.

Reduction of Fluid Loss

Two types of fluid loss to the formation can occur. These are seepage and lost circulation. The most common brine fluid loss is seepage. Seepage is the slow and steady flow of brine into the formation. Lost circulation, which does not occur often with brines, generally implies a fracture or breakdown of the formation, resulting in rapid fluid loss. The focus of this section is prevention of seepage losses to the producing formation.

Seepage loss occurs when the hydrostatic pressure head on the fluid is greater than the formation pressure. Seepage can range anywhere from near zero to as much as several barrels per hour. Seepage into the completion interval should be controlled for several reasons. Well pressure

control is difficult when the wellbore fluid is seeping into the formation. In some cases, there are brine losses to one formation section and gas influx into the wellbore from another formation section. The influx of gas may be stopped by limiting the brine loss rate to the point where gas is not able to flow into the wellbore. Even though brines are designed to minimize formation damage, they are foreign to the formation. Therefore, uncontrolled brine penetration to the formation may disrupt the chemical balance and cause damage. One method of reducing excessive seepage loss is to decrease the pressure differential by reducing the density of the brine. Other solutions to seepage loss include raising the viscosity of the brine and adding sized bridging particles.

Fluid Loss Strategies

The most apparent method of fluid loss control is reducing density to lower the hydrostatic head against the formation pressure. However, well control and safety must be taken into consideration before reducing the fluid density.

The most common form of fluid loss control is to pump a viscous pill into the thief zone. This viscous pill consists of the CBF with the addition of polymer viscosifiers. The viscous fluid pill reduces the seepage rate. The rate of fluid influx to the formation depends on the pill viscosity and hydrostatic head exerted on the column of the brine. The two most common viscosifiers are:

- TETRAVis L Plus, prehydrated HEC (hydroxyethylcellulose) and
- BioPol L, prehydrated xanthan gum.

Viscous pills are the ideal first option to slow down the fluid loss rate and are applicable in formations with permeabilities less than one darcy and temperatures within the limits of the polymer selected. These pills are solid free and degrade with respect to temperature, losing fluid viscosity with time. Therefore, well flowback will remove the remains of the viscous fluid from the formation.

In cases of extremely high fluid loss, bridging solids may be used in combination with increased viscosity to stop the seepage. Usually two types of bridging solids are used. These are calcium carbonate (CaCO_3) and sized common salt (NaCl). Calcium carbonate may be added to any viscous fluid. Sized salt pills must be saturated with sodium chloride to prevent dissolution of sized salt into the brine.

In order to select the proper sized bridging agent, the size of the pore holes to be bridged must be known. In general, particles will bridge an opening three to five times larger than the bridging particle diameter. Using this rule of thumb, a formation with an average pore size of 10

microns would require a bridging agent with particles averaging two to three microns in diameter. Proper bridging agents have a particle size distribution which allows a much tighter seal on the formation face, resulting in better fluid loss control. For example, the two to three micron bridging agent mentioned previously would most likely have a particle size distribution ranging from one micron to 20 or 30 microns. This material would have particles sufficiently large enough to bridge off the pore throats as well as particles small enough to form an impermeable cake. Bridging materials range in size up to fractions of an inch in order to handle the full range of fluid loss problems encountered in the field.

The fluid loss pill design must include planning for the cleanup of bridging solids after the completion process. When perforations are sealed or the open hole is bridged off, the removal of the bridging solids is not likely to be uniform. Even though a dissolving fluid is passed from the wellbore to the formation (acid, brine, or solvent washes) or from the formation to the wellbore (produced fluids), some perforations or sections of the formation face could remain sealed off, regardless of the type of bridging solids. If sections of the formation remained sealed at the wellbore, then the flow dynamics of the formation may be dramatically altered, and, as a consequence, production can be impaired.

The two methods for removing bridging materials are:

1. CaCO_3 spontaneous cleanup when the formation is allowed to flowback or by acid treatment with 15% hydrochloric acid, and
2. salt removal by pressure differential during flowback, dissolution by formation water, or washover with undersaturated brine.

Filtration

The purpose of filtering completion/workover fluids is to prevent damage to the producing formation. If dirty fluid is used, it can result in irreparable damage to the permeability of the formation. Not only do dirty fluids reduce formation permeability, they also reduce the permeability in gravel packs. In order for a fluid to be nondamaging to the producing formation, the solids must be removed. The contaminating solids can come from mud residue left by ineffective displacement or perforation debris. All of these contaminants can and will plug perforations.

Filtering involves the screening or mechanical separation of solids from fluids. Clear brine fluid filtration is, essentially, a protective process. In order to arrive at a satisfactory degree of filtration, an evaluation of the contaminants involved is necessary. The critical factor in the case of solid contaminants in the fluid is the particle size distribution.

Filtration Equipment Sizing

Estimating the properly sized filtration unit is an approximation at best, but some useful guidelines can help. The main objective is to have the longest runtime or filter unit operating time (least amount of downtime) achievable within the limits of the physical equipment size. The two most important criteria are the flow rate and solid content of the fluid. Realistically, deck space may also be a factor in the decision.

Flow Rate. The range of flow rates anticipated should be the primary selection criterion. Flow rates for plate and frame filters are normally between 0.8 bbl/min and 1.0 bbl/min per 100 ft² of filter area. A value on the upper end of that range suggests the need for a larger unit to allow for some flexibility when handling surges in flow.

TABLE 52. Typical Filtration Equipment

TETRA Filtration Equipment			
Unit	Filter Area	Flow Rate	Footprint
	ft ²	bbl/min	L x W
SafeDEflo 600	600	6 - 8	22 x 15 feet
SafeDEflo C600	600	8 - 10	16 x 15 feet
SafeDEflo 1100	1,100	8 - 12	24 x 15 feet
SafeDEflo 1300	1,300	12 - 14	26 x 15 feet
SafeDEflo 1500	1,500	14 - 20	26 x 15 feet

Fluid viscosity will also vary with salt composition. A highly saturated summer blend fluid may have viscosity as high as 30 cp. The viscous drag of such a fluid in the filter cake will reduce filter throughput.

Solid Removal Rate, v_{sol} . There are several ways to measure the solid content of a brine, and they have varying degrees of accuracy. Percent by volume (p_{sol}) will be used in this discussion. The upper limit of suspended solids for efficient filtration is about 2% by volume. Any filter will only operate efficiently at this rate for short periods of time. More realistic levels of solids will probably range from 0.05% to 0.5% by volume. Using volume percent is subject to many assumptions, but this discussion is provided to give only general guidelines.

Use Equation 31 below to estimate the rate in ft³/min that solids will be removed by the filter, using the brine flow rate (Q) in bbl/min and solid content in percent by volume (p_{sol}).

EQUATION 31.

$$v_{sol} = Q * p_{sol} * 0.056$$

v_{sol} = volume of solid removal rate, ft³/min

Q = flow rate, bbl/min

p_{sol} = solid content, vol %

$$0.056 = \text{ft}^3/(\text{bbl}\cdot\%)$$

EXAMPLE O. Solid Removal Rate

Find:

v_{sol} , solid removal rate

Given:

$Q = 10$ bbl/min

$p_{sol} = 0.35\%$ by volume

$$v_{sol} = Q * p_{sol} * 0.056$$

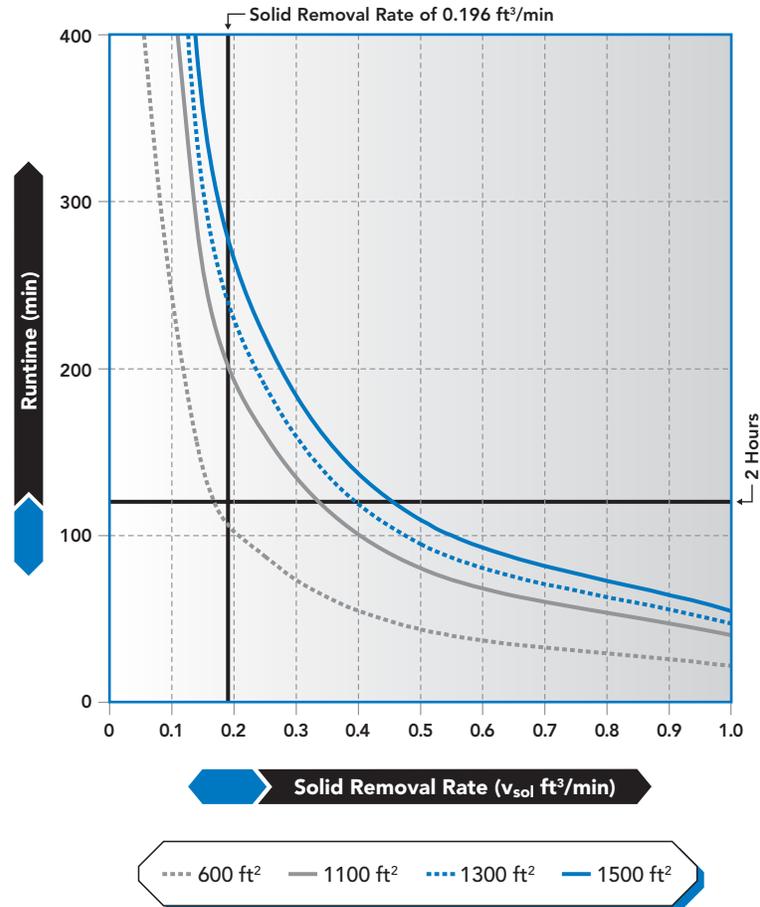
$$v_{sol} = 10 \text{ bbl/min} * 0.0035 * 0.056$$

Answer:

$$v_{sol} = 0.002 \text{ ft}^3/\text{min}$$

Then, to estimate runtime, locate that solid removal rate on the bottom axis of Figure 22 and move up to the filter curves to see the various runtimes for each filter. We have drawn a line for our example solid removal rate (v_{sol}) of 0.196 ft³/min. Filter size is indicated in square feet of filter area for four different filter sizes. Clearly, the larger the filter area, the longer the runtime. It is worth noting that if your target is a two hour runtime, you will need to determine your solid removal rate and then select your filter size accordingly. As you can see in Figure 22, solid removal rates between 0.18 ft³/min and 0.45 ft³/min will allow you to achieve a filtration unit operating time of two hours (120 min) if you select the appropriate filter.

FIGURE 22. Approximate Filter Runtime



Opening a filter press to discharge solids and precoat takes between 30 and 60 minutes each time. A runtime of 120 minutes with a 45 minute cleaning and precoat cycle would mean that you could accomplish roughly nine complete cycles in a day, resulting in six to seven hours of downtime for precoating each day.

Larger filter units mean fewer downtime cycles per day. Using the filtration removal rate of 0.196 ft³ from the previous example, runtimes for the different size filter units are shown in Table 53.

TABLE 53. Filtration Runtime Examples(10 bbl/min and 0.35% by vol solid content or V_{sol} 0.196 ft³)

Filtration Unit	Runtime/Cycle	Cycles/Day	Downtime/Day
ft ²	min		hr
SafeDEflo 600 and C600	111	9.2	6.9
SafeDEflo 1100	204	5.8	4.3
SafeDEflo 1300	241	5.0	3.8
SafeDEflo 1500	278	4.5	3.3

This brief overview was intended to show how to size a filter and explain the effects of high solid loading. The following paragraphs explore some of the finer aspects of filtration theory.

Filtration Theory

Filter Rating Systems. There are several ways to rate the efficiency of a filtration operation. Capabilities are often provided for cartridge filtration units. Cartridge filters either have a *nominal rating* or an *absolute rating*.

Nominal Rating. A particle size, in microns (a one-thousandth of a millimeter), may be provided for a particular filter element or cartridge such as a 10 micron cartridge. This value implies that the filter is capable of removing particles as small as 10 microns. These values are very dependent on test methods; they are meant to provide a helpful guideline, but are difficult to use when comparing one filter to another.

Absolute Rating. The size, in microns, of the largest spherical particle that will pass through a filter element. The efficiency of an absolute rated cartridge is measured in terms of *Beta Ratio*. A standardized ANSI (American National Standards Institute) test is used to measure the beta ratio—the number of particles of a particular size that are entering a filter, over the number of the same size particles that are leaving a filter in the filtrate (upstream divided by downstream). A beta ratio will always specify the micron size of the particles with which the test was conducted. A beta ratio of $B_{10} = 50$ means that there were 50 times more 10 micron particles in the influent than in the effluent from the filter.

Below a certain threshold particle size, each filter will have a different beta ratio for each particle size. A curve can be drawn for a particular cartridge or filter element showing beta ratios at various particle sizes.

Surface Filtration. Surface filtration works largely through direct interception. This means that particles larger than the pore size of the medium are stopped at the upstream surface of the filter. The particle

size prevents them from entering or passing through the pores. Surface type media are not perfectly smooth on their upstream surfaces, nor are their pores perfectly uniform in shape or direction.

Typically, when surface type filters are exposed to the flow of contaminated fluid, two effects—the gradual reduction in effective pore size and the building of a cake bed—start to take place almost immediately.

Gradual Reduction in Effective Pore Size. The effective pore size of the medium is gradually reduced, as some of the pores become partially blocked by particles. This reduction makes the filter become more effective in removing fine particles. Pore size reduction can be caused by the retention of extremely small particles within the pores by absorptive forces. It can also occur due to the partial intrusion of soft, deformable particles into the pores, acting under the forces generated by fluid flow, so that those pores are effectively reduced in size. Deformable particles have the ability to conform more closely to the shape of flow passages, thus blocking them to a greater degree than hard particles might. They can also form a slime or gel that can completely clog the filter.

Building of Filter Cake. A cake or bed of filter aid (DE) particles starts to build on the surface of the filter element (filter cloth). This build up of filter aid (filter cake) actually does the filtering. As operating time continues, this filter cake becomes progressively finer due to the same clogging or trapping mechanism noted previously. The filter cake then becomes completely clogged, restricting the flow of fluids through the medium. This effect can be noted by an increase in pressure differential through the filter press.

The pleated paper filter element is a typical example of surface filtration. Dirt retention is directly related to surface area. It is here that the theory of absolute filtration is applied.

The *absolute rating of a filter* is a frequently misunderstood and misused concept. The largest particle passed by a filter is not a function of the size of the openings in the filter medium; it is a function of the flow through the filter, the particles, the filter medium, the pressure and flow pulsations, and many other factors. The zeta potential, electrostatic charge connection of the particles, fluid, and filter media all interact to determine the size of particles captured under a given set of conditions. Any change in these factors will affect filtration conditions, which will, in turn, affect particle distribution downstream of the filter.

Over time, the absolute rating has mistakenly come to mean attempting to define the largest particle found downstream of a filter under operating conditions. The absolute rating is actually a measurement of the largest glass sphere the filter will allow to pass when exposed to a low

pressure differential and nonpulsating flow. Under actual operating conditions, with the infinite array of variables mentioned above, there is no strict relationship between absolute rating and the particle size distribution in the effluent. However, when used as a qualitative measurement for filter selection, the absolute rating is the best guideline available.

Depth Filtration. This type of filtration employs a deep, porous structure. The mechanism of filtering then becomes much more complex. The path through the filter is much longer and more random, providing greater possibility for both direct interception and dirt retention. In general, larger particles will tend to be trapped in the surface layers with the finer particles trapped by succeeding layers. If necessary, the structure of the filter can be density graded. This can be particularly advantageous where the particle sizes or the contaminants are widely distributed. When contaminants are of a more or less uniform size, a surface filter may be equally effective. Depth filtering also gives a higher pressure drop than a surface filter.

It is possible for the overall performance of a depth type filter to be better than that given by the purely mechanical action of direct interception. The inertia of particles that are impinging directly onto the filter medium may generate absorptive surface forces. As a result, the depth filter may trap and retain particles finer than those trapped by pure mechanical filtration alone.

Nominally rated filter elements (cartridges) are typical examples of depth type media. Cartridge filters are produced by using a wide variety of configurations and materials of construction. Filter media include yarns, felts, papers, resin bonded fibers, and woven wire cloths. The filter element is normally designed as a disposable component and is meant to be replaced with a new cartridge when clogged. Cartridge filters are compact, reliable, easy to operate, and require less operator training than most other types of filtration equipment.

In heavily contaminated systems, cartridge filters are most often used downstream of other types of filtration devices for final product clarification. The system most commonly seen in the oil industry utilizes a plate and frame filter press that is precoated with diatomaceous earth (DE) for primary filtration and a downstream cartridge unit, which functions as a guard/polishing filter.

Cake Filtration. Cake type media are generally employed for removal of solids in significant bulk. Usually, the action of fluid flow will cause separate, loose, discrete particles to form into a cake on a supporting screen. The voids between the particles form the pores and flow passages required for filtration. One typical material used to form a cake is diatomaceous earth.

Brine Filtration

Plate and frame filters are large multiplate pressure filters that can treat up to 20 bbl/min. To enhance the filtration process, a filter aid is utilized to precoat the filter cloths that are supported by the plates. The plates and filter cloths merely provide a support for the filter aid which does the actual filtration. A number of precoating materials are available. The most common filter aid in CBF applications is diatomaceous earth (DE). From this, the term *DE Filtration* was derived.

When this type of filtration system is utilized, certain parameters are controlled that greatly influence the effluent quality of a filtrate. Some of these parameters are porosity, permeability, and pressure differential. Some of the limiting parameters in determining the optimum filtration system for a particular job are: rig space, equipment size and weight, volume capacity, flow rates, desired effluent quality, equipment flexibility, and cost.

In this industry, our goal is to achieve the most efficient and cost effective means of filtration that fits within the specific parameters of a given application. As previously mentioned, the most commonly used filtration system in the area of completion/workover fluids utilizes a filter press as a primary filter with a cartridge filter downstream. The main function of the filter press is to remove all suspended solids; the function of the cartridge filter is to serve as a guard, or polishing filter, and to guard against the loss of DE into the formation should a filter cloth tear.

The filter presses available in the field consist of a series of vertical chambers arranged in parallel. Frame filter presses are produced by stacking flush plates with distance frames separating them. A chamber filter press is produced by stacking a series of recessed plates. In either case, each plate carries a filter cloth, or other suitable filter medium, and the stack of plates is compressed. Most commonly, a hydraulic system is used to expand and retract the ram of the filter press.

The product to be filtered is fed into the press under pressure. The filtrate passes through the filter media and out of the press. At the same time, solids are retained in the form of a cake on the filter media with each chamber of the press performing as a separate unit. Initially, the cloth and DE precoat act as the filter, but as solids and additional DE are collected and built up on the surface, they gradually assume the function of the primary filter medium. Filtering then continues with increasing efficiency until the cake has built to an optimum thickness.

Pumping pressure progressively builds up to compensate for the loss of flow rate until, eventually, the cake is fully formed and filtrate flow is negligible. Pumping is stopped and the fluid is displaced from the filter by compressed air (blow down). The press is then discharged; this is accom-

plished by separating the plates and allowing the cakes to drop out. After being discharged, the press is washed out, closed, and made ready for the next cycle.

Filter Cloths. Filter cloths, often referred to as *septums*, provide the support for the filter aid. A wide variety of filter cloths may be used, although the most common woven materials are nylon and polypropylene. The smooth surface and good flexibility of these cloths promotes easy cake removal. Weave also affects the tendency for the cake to clog the cloth so that satisfactory performance can only be established on empirical lines. Economical operation may depend upon usage of a relatively expensive filter cloth with proper attention given to cleaning so that individual cloths are not damaged.

Diatomaceous Earth. Diatomaceous earth (DE) is a nonmetallic mineral composed of the skeletal remains of microscopic, single celled aquatic plants called diatoms.

Diatomaceous earth is predominantly amorphous silica (noncrystalline silicon dioxide). It may also contain small amounts of crystalline silica quartz; oxides of calcium, magnesium, iron, and aluminum; and certain trace elements, which occur naturally in the Earth's crust. Physically, the diatom skeletons are intricate structures having many submicron pores. They occur in a large variety of shapes, much like snowflakes. These relatively noncompressible structures occur mainly in particles of 10 to 200 micrometers in diameter. One of the major uses of various grades of processed diatomite is as filter aids.

The primary functions of filter aids are improved filter efficiency, increased filter life, and improved flow rates. In order for a filter aid to perform, it must: (1) form a porous cake, (2) have a high surface area and a narrow particle size distribution, and (3) have an irregular shape.

Automated DE Delivery Systems. Automated DE delivery systems were originally developed in response to the Control of Substances Hazardous to Health (COSHH) regulations regarding airborne crystalline silica. Automated DE delivery systems are designed to reduce the risk of personnel exposure to airborne crystalline silica, which can be found in naturally occurring diatomaceous earth.

Automated DE delivery systems have numerous other HSE benefits. For years, diatomaceous earth has been supplied to filtration locations in pallets containing 50-pound paper sacks. To introduce the DE filter aid into the filtration process, filtration personnel were required to handle individual sacks of DE, opening each sack and emptying it into the DE slurry (Add Mix) tank. This process required lifting and carrying the heavy sacks and using cutting devices to open them. This process also

created dust and resulted in solid waste requiring disposal. To address these HSE issues and automate the DE introduction process, TETRA recently introduced the SafeDEFlo™ diatomaceous earth automated delivery system for use in Gulf of Mexico filtration operations.

The SafeDEFlo delivery system utilizes intermediate bulk carriers (IBCs), which hold 1,000 pounds of DE material. The IBCs are filled with DE and then transported to a filtration location where they are paired with a dispensing system that is operated through a pneumatic control panel. The SafeDEFlo system provides accurate DE dispensing and a safer, cleaner work area without the need for disposal of sacks, shrink wrap, or pallets.

Precoating

The first step in preparing a plate and frame filter for operation is to build up a precoat of filter aid on the filter cloth (septum).

The purpose of the precoat is:

1. to prevent the filter septum from becoming clogged by impurities, thus prolonging septum life,
2. to produce immediate clarity, and
3. to facilitate the cleaning of the septum at the end of the cycle.

Precoating is accomplished by circulating a slurry of filter aid and filtered or clear liquid between the filter and the precoat tank. Since most of the filter aid particles are smaller than the openings in the septum, they form a thin filter cake by bridging these openings. This filter cake can be upset by air bubbles, sudden changes in pressure, or vibrations. This causes the filtrate to become turbid until the upsetting influences have been corrected.

Amount of Precoat. The amount of precoat is generally 10 to 15 lb of filter aid per 100 sq ft of filter area. The greater amount is used when distribution of flow in the filter is poor or when breaking in new filters. If it is perfectly distributed, 10 lb of filter aid per 100 sq ft of filter area will give a precoat of approximately 1/16 inch in thickness. Precoat slurry concentration depends primarily on the ratio of filter area to filter and piping volume.

Precoat is added to a quantity of working fluid in the precoat mix tank. Vigorous mixing is required to get the light DE adequately mixed. The precoat slurry is then circulated in a closed loop through the filter until the returning fluid is once again clear.

Precoating Rate. The precoat rate depends primarily on the viscosity of the fluid used. The rate should be sufficient to maintain filter aid suspension, but not so fast as to cause erosion of precoat in the filter. For water,

a typical rate is one to two gal/sq ft of filter area per minute. Extremely viscous liquids may require rates as low as five gal/sq ft per hour. A general rule for precoat is to precoat at that rate which gives a pressure differential of approximately two psi. For water, an upward velocity of at least four ft/min is required for proper filter aid suspension.

Filtering

After the precoat filtrate has cleared up, the filter is put on stream by:

1. starting the body feed pump,
2. opening the line from the filter feed pump, and
3. simultaneously closing the line from the precoat circulating pump so that flow through the filter is continuous and without sudden fluctuations in pressure.

If the filter is precoated using filtered liquid, it is best to refill the precoat tank immediately by directing all or part of the filtrate to it. Filling the precoat tank at the end of the cycle may cause problems. Since flow through the filter may drop suddenly, the time required for filling may be excessively long.

Body Feed Addition. Insufficient body feed decreases active filtration time. The body feed is completely surrounded by undissolved solids and does not, therefore, increase cake permeability. Cake permeability only increases the cake thickness without adding anything to its permeability. From this point, as body feed is increased, throughput increases slowly and then rapidly for a short span of time. The rate increases and then tapers off; throughput stabilizes and then actually decreases once again, because cake permeability is no longer increased with additional amounts of body feed. Excessive body feed results in a sudden increase in pressure as the cake bridges between the plates. This increase causes a sudden decrease in filter area, and can also result in severe damage to the plates and loss of clarification. In general, proper body feed maintains high permeability of the filter cake and characteristics similar to depth filtration.

Several grades of diatomaceous earth are available as filter aids. In general, the coarser grades provide higher flow rates and lower effluent clarity. The opposite also holds true with the finer grades resulting in lower flow rates and higher effluent clarity.

Rig Practices and Filtration Performance

While a two micron filtration level is generally used as an acceptable standard, the total suspended solids left in the effluent should be of great concern. No fluid containing more than 1,000 ppm should be considered clean. Efforts should be made to reduce solid content to a level as

low as practically possible. Strict adherence to sound rig practices, careful fluid management, and competent operators will produce worthwhile results, paying off in improved production rates and extended well life.

In addition to occurring in the well itself, fluid contamination can occur in storage facilities, during transportation, and in surface circulating systems. Utmost care should be taken to minimize the possibility of fluid contamination. It is most important that the entire surface system be cleaned before the clear brine fluid is brought in. It is important that the flowline, shale shaker, sand traps, solid control equipment, return line, pits or tanks, equalizing lines, hopper, mud pumps, mud manifolds, kelly, kill line, choke, and manifold be flushed and cleaned prior to taking on the brine. Although rig time and associated costs are inarguably expensive, it is invariably more cost effective to prevent fluid contamination than it is to remove solids by filtration after they have occurred.

One of the major difficulties in evaluating a filtration process is carrying out onsite determinations of effluent quality. The following components should be considered when analyzing a filtration process for clear brine fluid applications:

1. total suspended solids,
2. maximum size of particles at specified solid content, and
3. cost per barrel.

It is important to understand the different variables that are encountered during the filtration of brines. Some of those variables are flow rate, pressure differential, cycle life, solid content, and fluid viscosity. During the filtration process, the filtration operator has almost absolute control over the variables mentioned above; it is up to the operator to get the maximum efficiency out of the filtration equipment.

Clarity

The clarity or solid free nature of brines is the most important aspect of their use as completion fluids. Brine clarity is measured by the quantity of the total suspended solids in a brine.

Briefly, two parameters can be determined which relate to clarity: (1) turbidity and (2) solid content in milligrams per liter (mg/l) or parts per million (ppm). These two parameters do not always correlate well. If absolute solid content is required, calibration curves must be determined in order to relate turbidity units to solid content in mg/l, ppm, or percent by volume. Procedures to prepare these curves are detailed in "API RP 13J: Recommended Practice for Testing Heavy Brines."

In certain situations, turbidity is used as a relative measure of clarity. For example, turbidity measurements can be taken upstream and downstream from a filter unit and then compared to one another. If the turbidity of the downstream (effluent) sample is lower than that of the upstream (influent) sample, then the general conclusion is that the effluent sample contains fewer solids. Test filters may also be used for this purpose. If the effluent sample filters more quickly through a test filter than the influent sample does, the conclusion is that the effluent contains less solids.

Standards or specifications for clarity are difficult to set. Ideally, a brine should have a near zero turbidity or a solid content of near zero mg/l. A common means of measuring turbidity is by the light scattering ability of suspended solids. Turbidity measurement is reported in nephelometric turbidity units (NTUs). A value of 20 NTUs is considered the upper limit of acceptable brine clarity.

Clarity Problems—Contaminants and the Formation of Solids

The presence of contaminants, either solid or gaseous, can have a serious impact on the potential for localized corrosion, especially on the probability that environmentally assisted cracking (EAC) could initiate a catastrophic cracking event. The presence of solids or scale can lead to the establishment of a concentration cell, or crevice corrosion, which may initiate pitting or cracking of the metal. Additionally, acidic gaseous contaminants, like CO_2 and H_2S , can induce pitting or cracking, especially when CRA metallurgies are used. As a consequence, the impact of the following contaminants on both general and localized corrosion, given susceptible combinations of specific fluids and metallurgies, must be considered.

Miscellaneous Contaminants

Iron. When additives like corrosion inhibitors are introduced into fluids, turbidity will often increase even though no solids have been added. Also, meta-stable dissolved solids, such as ferrous chloride (FeCl_2) or ferric chloride (FeCl_3), may not show up on turbidity or suspended solid tests. However, these compounds may precipitate as insoluble solids when the brine chemistry changes. More significantly, these contaminants or the presence of iron, in general, may lead to precipitation of solids, owing to the ease with which hydrated iron species are formed.

The formation of these hydrated species leads to a lowering of the pH (increase in acidity). This is especially true with ferric compounds. As a consequence, the issue of enhanced corrosion may have to be

addressed. Once formed, these hydrated iron species at pH levels of ~3 or higher can yield gelatinous hydrated oxide, ferrous Fe(II), or ferric Fe(III) hydroxides that precipitate depending on the pH.

Carbon Dioxide. The introduction of carbon dioxide into divalent brines (calcium or zinc) can lead to increased turbidity and solid formation, owing to the formation of calcium carbonate (CaCO_3) or zinc carbonate (ZnCO_3), both of which are insoluble in aqueous media.

Dissolved bicarbonate ions, present in most naturally occurring sources of water, will react with calcium or zinc ions in brines to form calcium or zinc carbonate. Precipitation of carbonate salts will lower the pH of the fluid, raising corrosion concerns.

Hydrogen Sulfide or Sulfides. The presence of the sulfide ion from hydrogen sulfide (H_2S) can lead to turbidity or solid deposition problems due to three different phenomena:

1. the formation of insoluble iron sulfide salts,
2. the formation of insoluble zinc sulfide salts (in zinc brines), and
3. the formation of free elemental sulfur by the slow oxidation of the sulfide ion.

Invariably, the metal sulfides that precipitate in the presence of hydrogen sulfide are really polysulfides (MS_x) in which elemental sulfur is chemically bound to the sulfide.

Like CO_2 , H_2S is a weak acid in water. As a consequence, formation of insoluble metal sulfide salts will lower the fluid pH and have the effect of accelerating corrosion.

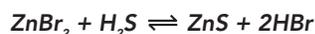
H_2S itself is a strong promoter of hydrogen embrittlement, which can be manifested as EAC. See "Sulfide Stress Cracking," beginning on page 190.

Bacteria. Although normally bacteria do not survive in basic media or highly concentrated brines, the potential danger of certain bacteria in dilute brines must be recognized. Sulfate reducing bacteria can produce H_2S from trace amounts of the sulfate ion, which can lead to increased turbidity and/or insoluble matter.

Seawater. If a CBF containing calcium comes into contact with seawater, the levels of bicarbonate ions and sulfate ions that are routinely present in seawater may result in the formation of solid calcium carbonate and calcium sulfate. In addition, the high chloride concentration in most brines will result in the formation of sodium chloride crystals. Seawater is a rich source of bacteria and other microorganisms.

Formation of Solids

Sulfide Precipitation. As in the case of carbonate precipitation, the formation of insoluble sulfides leads to an increase in acidity. This is illustrated below in the formation of hydrobromic acid (HBr) from the reaction of H₂S with zinc bromide (ZnBr₂).



The increased acidity with the introduction of a large amount of H₂S at some point redissolves the formed zinc sulfide (ZnS), i.e., the reaction becomes reversed. This process lessens the amount of solid formed, but, clearly, it also may have health, safety, and environmental consequences due to a greater release of H₂S.

Calcium or Zinc Hydroxide Precipitation. With an increase in pH, divalent brines may form hydroxides and increase turbidity, since these species are rather insoluble. As a consequence, the practice of increasing the alkalinity of calcium or zinc brines to reduce the brines' susceptibility to corrosion must be undertaken with great care. Otherwise, filtration and fluid weight up will be needed, owing to the density loss which will occur as a result of the precipitation of calcium hydroxide (Ca(OH)₂) or zinc hydroxide (Zn(OH)₂).



Contact a TETRA fluids specialist if you have concerns about zinc precipitation. TETRA has developed a number of solutions to address this problem.

Sodium Chloride Precipitation. The precipitation of sodium chloride from brine mixtures containing high concentrations of sodium and chloride ions can lead to solid control problems. Being soluble only to an extent of ~26%, sodium chloride (NaCl) is the least soluble of the common brine salts. Furthermore, in contrast to most other soluble salts, its solubility does not increase significantly with a rise in temperature, and it decreases in the presence of other salts. As a consequence, care needs to be exercised when calcium chloride (CaCl₂) is added to solutions containing sodium bromide (NaBr).

Conclusion

Each of the sections in this chapter represents a small sampling of a field of applied science or technology. Only those aspects that are directly

applicable to clear brine fluids and their application to oil and gas well completion and workover operations have been presented here. A vast body of literature exists for each of these disciplines outside the context of this manual. The best sources of additional information are the publications of professional societies such as the following:

Organization	Website
American Petroleum Institute (API)	http://api-ec.api.org
Society of Petroleum Engineers (SPE)	http://www.spe.org
NACE International—The Corrosion Society (NACE)	http://www.nace.org
The Filtration Society	http://www.filtsoc.com
American Filtration & Separations Society (AFS)	http://www.afssociety.org

The previous list represents only a few of the many valuable energy industry resources available. If you have a deeper interest in a particular field, these organizations will be your best starting point.

In addition, TETRA will endeavor to improve and update the online edition of the *Engineered Solutions Guide for Clear Brine Fluids and Filtration, Second Edition*. All of us who have invested time and energy developing this manual hope you will find it the preferred guide when you are planning a well or heading for the field. Your corrections, comments, and suggestions regarding this document are always welcome, as we realize that a work such as this can always be improved.

Suggestions, Corrections, or Updates

Please send any editorial suggestions, corrections, or updates to the following address:

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